GEOLOGIC FRAMEWORK AND DESCRIPTION OF COALBED GAS PLAYS

By Dudley D. Rice

INTRODUCTION

Coal-bearing areas in the United States, including Alaska, which have coalbed gas potential are shown in figures 1 and 2. Figure 3 shows the location of 39 plays within 14 provinces that have potential for additions of reserves of coalbed gas and were quantitatively assessed by methods described elsewhere in this CD-ROM. The plays are listed in table 1. Brief descriptions of those provinces and plays for which potential additions to reserves were assessed are given in this chapter; in addition, the play descriptions are included under each province. In most of these provinces, geologic summaries of coalbed gas potential and estimates of in-place coalbed gas resources have been made by Department of Energy and (or) Gas Research Institute contractors (see ICF Resources Inc., 1990 and Schwochow and Stevens, 1993a for references). The status of exploration and development of coalbed gas resources in these provinces is given by Schwochow and Stevens (1993a).

The development of coalbed gas in the United States resulted mainly from a special tax credit (Section 29 of the Crude Oil Windfall Profits Tax), which is given for the production of unconventional gas, such as coalbed gas, from wells drilled and completed between the period December 31, 1979 and January 1, 1993. Major advances in exploration and production technology have taken place over that time. According to the Gas Research Institute, reserves of coalbed gas in the United States increased from about 5.1 to 11.4 TCF and production increased from about 195 to 700 BCF from 1990 to 1993. By the end of 1992, more than 5,400 wells were producing coalbed gas. Currently, coalbed gas accounts for about 6 percent of the total United States gas reserves and 3 percent of the gas production. Most of the reserves and production are from the San Juan and Black Warrior Provinces (022 and 065).

The total amount of water produced from all coalbed gas wells is relatively small (<20 percent) when compared to all gas wells. However, the volume of water produced from an individual coalbed-gas well is generally much higher than that from other types of oil and gas wells. The disposal of this water produced with coalbed gas not only affects the economics of development, but also poses serious environmental concerns. The challenge is to modify the disposal methods as the environmental regulations become more strict. Water disposal can vary from inexpensive methods, such as discharge into streams, to more costly alternatives, such as underground injection and surface discharge after treatment. Discussion of various concerns and options related to produced water is provided by Schwochow and Stevens (1993b).

Coalbed-gas plays were defined on the basis of factors that control the occurrence and productivity of coalbed gas. These factors include, but are not limited to, thickness, heterogeneity, depth, and composition of coal, seals, gas content, gas composition, permeability, pressure regime, structural setting (folds, faults, joints, cleats), hydrology (ground-water flow and quantity and quality of water), and conventional trapping mechanisms, such as structure. In general, coalbed gas plays for potential additions to reserves extend from depths of 500 to 6,000 ft below the surface. At shallower depths, gas contents are generally too low for commercial production. At greater depths, permeability is generally too low, because of increased stress, to sustain commercial flow rates in spite of higher gas contents. Many aspects related to the occurrence and development of hydrocarbons from coal, including geology, engineering, production, and economics, are provided in a book edited by Law and Rice (1993). In addition, Rice and others (1993) gave a summary of coalbed gas with information on environmental issues, mainly methane emissions and water disposal.

Coalbed gas is developed in two different settings in which the geologic and hydrologic controls may be the same. These settings are in association with and away from underground coal mining. The different manner in which the coalbed gas is produced in these two settings will affect the recoverability. Pressure reduction during coal mining, particularly underground, results in the release of coalbed gas, which is mostly methane, at shallow depths. This release results in both safety hazards to the miners, which affects productivity, and environmental concerns because the methane-rich gas is a potent greenhouse gas. Although this mining-related coalbed gas is commonly ventilated to the atmosphere to prevent safety concerns, only recently have limited efforts been made to market this gas which will mitigate environmental concerns. The Federal Government, through the Climate Action Plan, is encouraging coal mines to recover and utilize this methane which would reduce the emissions and probably benefit the mines and their communities.

The type of wells drilled to recover coalbed gas from underground mining areas are (1) vertical wells drilled from the surface to coalbeds several years in advance of mining; (2) gob wells drilled from the surface which remove gas released from rocks above and below the coalbed during and after mining; (3) horizontal boreholes drilled from inside the mine to degasify the coalbed to be mined; and (4) cross-measure boreholes drilled from inside the mine to degasify the surrounding strata. Most of the gas from underground coal mines is recovered by gob wells. As a variation, vertical wells have recently been drilled into some abandoned mine workings in which gas has accumulated over a period of tens of years. The potential for recovery of significant amounts of coalbed gas from underground mining areas is mainly in the Appalachian Basin Province (067), Black Warrior Basin Province (065), and Illinois Basin Province (064) in Alabama, Illinois, Kentucky, Pennsylvania, Virginia, and West Virginia. In the Rocky Mountain area, some potential for recovery of coalbed gas from underground mining areas occurs in Colorado, Utah, and Wyoming. Statistics on underground coal mining and related gas emissions are given by Sprouls (1993) and Trevits and others (1993).

The development of coalbed gas in association with mining has been hindered by two problems. The first is ownership of the gas (coal versus gas mineral rights), and the second is the possible conflicts that arise between activities of coalbed gas development and coal mining. These potential problems and possible solutions are discussed by Levine (1993).

The largest resources of coalbed gas are away from mining areas where coals are commonly deeper. Generally, vertical wells are drilled in this setting with a variety of completion techniques ranging from hydraulic fracturing of wells with casing to open holes, some with enlarged cavities.

REGION 2–PACIFIC COAST

In the Pacific Coast region, Tertiary coal with potential for undiscovered, recoverable resources of gas is restricted to tectonically complex basins in western Washington. In-place coalbed gas resources for the area represent about 3 percent of those estimated for the United States.

WESTERN WASHINGTON
(PART OF PROVINCE 004)

By Samuel Y. Johnson and Dudley D. Rice

Three coalbed methane plays were considered in Western Washington, part of the Western Oregon and Washington Province (004). They are Western Washington–Bellingham Basin Play (0450), Western Washington–Western Cascade Mountains Play (0451), and Western Washington–Southern Puget Lowlands Play (0452)

A geologic summary of Eocene sedimentary basins of western Washington is provided by Johnson (1985). The coal reserves of western Washington are reviewed in Beikman and others (1961). Reviews of coalbed gas potential and exploration are provided by Choate and others (1984) and Pappajohn and Mitchell (1991).

Significant Eocene coal-bearing units in western Washington include the undivided Puget Group and the Chuckanut, Renton, Carbonado, Spiketon, Skookumchuck, and Cowlitz Formations. Cumulative thickness of the nonmarine Eocene sections in western Washington basins is commonly 10,000–20,000 ft, of which coals form a minor part. Coals of the Chuckanut Formation in northwestern Washington are fluvial in origin and occur in at least three zones (King Mountain, Bellingham, Lake Whatcom) with a cumulative coal-seam thickness of about 60–100 ft. Coals in the other stratigraphic units occur in west-central and southwestern Washington, have a delta-plain origin, occur in a variety of named and unnamed coal zones and seams, and have a cumulative coal-seam thickness of about 70–100 ft. Most coal seams are less than 10 ft thick; the approximately 25–30 ft thick Big Dirty seam in the Skookumchuck Formation near Centralia is the thickest coal seam in the region. Because of considerable and variable structural relief in western Washington, coals exposed at the surface in one area can be buried as deeply as 6,000 ft in other areas. Structural deformation and relief generally increase eastward toward the axis of the Cascade Mountains.

Coal rank in those parts of western Washington that are included in coalbed gas plays ranges from lignite to low-volatile bituminous. Thermal maturation associated with burial and with volcanism in the Cascade volcanic arc is the main control on coalification. The timing of maximum burial in the area is highly variable, ranging from late Eocene (Bellingham Basin) to early Miocene (foothills of the Cascade Mountains) to Holocene (Chehalis Basin), but the coal-bearing section in most of the area has experienced significant Neogene uplift and now occurs at or near the surface. This uplift may have resulted in degassing of some of the original coalbed gas. Heating generated by Cascade igneous activity began in the late Eocene and has continued to the present.

Coalbed gas throughout western Washington is inferred to be dominantly methane, but there are few documented analyses. A single gas analysis from a Puget Group coal seam at the surface in the John Henry Mine near Black Diamond Mine yielded methane of entirely biogenic origin. Coalbed gas from the Bellingham Basin area is reported to include significant propane in addition to methane. Isotopic analyses of gas seeps from old well casings in the Bellingham Basin indicate a thermogenic origin with mixing of some biogenic gas. Elsewhere in western Washington, higher rank coals in the Cascade Mountains are expected to have generated thermogenic gas, while lower rank coals to the west in the Puget Lowlands have probably generated only biogenic gas.

Coal-bearing strata have been folded into north- and northwest-trending folds and are cut by numerous north- and northwest-trending faults in a deformational event that began in the late Eocene and has continued sporadically (in both space and time) to the present. Fracturing associated with this deformation may have led to enhanced permeability within the coalbed reservoirs, but no information has been published on coalbed fractures and cleats in this area.

Information on coalbed hydrology is limited. In the Wilkeson-Carbonado area, the quality of produced water was sufficient to meet State and Federal requirements for surface discharge into the Carbon River. Saline water has been produced from sandstone interbedded with coal in both the Bellingham Basin and Black Diamond area.

Meager data are available on gas contents of coal beds in western Washington. For several wells in the Black Diamond-Wilkeson area, gas contents ranging from 200 to 518 Scf/t are reported. Coals from one well in the Bellingham Basin have a gas content of 100 Scf/t. Coal from the Skookumchuck Formation near Centralia has a desorbed gas content of about 20 to 75 Scf/t.

A history of methane-related underground-mine accidents in the region (most notably in the Black Diamond-Wilkeson area) and the presence of gas escaping to the surface through pools in the John Henry Mine near Black Diamond Mine also indicate gassy coals. Drilling data also indicate locally high reservoir pressures. For example, a 1911 well (TD = 1411 ft) in the Black Diamond area was abandoned because of gas flares as high as 25 to 30 ft and water flows. A small flow of gas is still present today at this well site, known as the "Flaming Geysers."

The in-place coalbed gas resources of western Washington have been estimated to be in the range of 3 to 24 TCF. The wide range of resource numbers results from using a scaling factor of 50 to 400 Scf/t for gas contents and by boosting the estimated coal reserve estimates by a factor of as much as 10. The lower number is probably more realistic for the play area and allows for up to a twofold increase in coal resources but uses a smaller scaling factor (50 to 200 Scf/t) based on the inferred coal rank.

Two surface coal mines are active; no underground mines are active in western Washington.

Since 1986, a total of 19 boreholes that can be broadly considered coalbed gas wells have been drilled in western Washington (14 in the Black Diamond-Wilkeson area of King and Pierce Counties, 4 in the Bellingham Basin of Whatcom County, and 1 in the Cascade Foothills of Lewis County). Most of these boreholes failed to adequately assess coalbed reservoir characteristics because the wells targeted primarily conventional gas reservoirs or because of technology problems related to complex geologic structure. Presently, no coalbed gas well is in production. In western Washington, existing infrastructure for coalbed gas development is favorable. A major gas pipeline originating in Canada passes through the Bellingham Basin and extends south through the Pacific Northwest urban corridor. The Black Diamond-Wilkeson area of King and Pierce Counties is located close to both gas delivery lines and end-user markets in Seattle and Tacoma.

0450. WESTERN WASHINGTON–BELLINGHAM BASIN PLAY (HYPOTHETICAL),
0451. WESTERN WASHINGTON–WESTERN CASCADE MOUNTAINS PLAY (HYPOTHETICAL),
0452. WESTERN WASHINGTON–SOUTHERN PUGET LOWLANDS PLAY (HYPOTHETICAL)

The target area for potential coalbed gas reserves is divided into three hypothetical plays based on geography and structure: (1) Western Washington–Bellingham Basin

Play (0450), (2) Western Washington–Western Cascade Mountains Play (0451), and (3) Western Washington–Southern Puget Lowlands Play (0452). The Western Washington–Bellingham Basin Play (0450) includes coals of the Chuckanut Formation in Whatcom County, northwest Washington. The play is bounded to the south by uplifted Chuckanut strata, to the east by an uplift of pre-Tertiary basement rocks, and to the west by the Strait of Georgia. To the north (both onshore and offshore), the play extends into Canada. Only the U.S. portion of the play was evaluated. As noted above, four boreholes that could be broadly interpreted as coalbed gas wells have been drilled since 1986. The potential for reservoirs in the Bellingham Basin Play (0450) is considered fair, with low coal rank considered the main limiting factor.

The Western Washington–Western Cascade Mountains Play (0451) involves coal beds in the structurally complex foothills of the Cascade Mountains in King, Pierce, Lewis, and Thurston Counties. Host rock units (the undifferentiated Puget Group and the Renton Formation, Carbonado Formation, and Spiketon Formations) are cut by numerous folds and faults. The play is bounded to the east by either faults that juxtapose the Eocene section with pre-Tertiary basement rocks, or by a depositional boundary where Eocene sedimentary rocks dip below a thick cover of Eocene and younger volcanic rocks. To the northwest, the play is bounded by the approximate facies contact between nonmarine rocks and marine rocks. To the southwest, the play boundary approximates the location of a structural boundary that separates a thicker, mainly nonmarine, highly deformed Eocene sequence from a thinner, mixed marine-nonmarine, less deformed Eocene sequence. As noted previously, 15 boreholes that could be broadly interpreted as coalbed gas wells have been drilled in the play since 1986. The potential for reserves in this play is considered fair, with structural complexity the main limiting factor.

The Western Washington–Southern Puget Lowlands Play (0452) involves coals of the Skookumchuck and Cowlitz Formations in Thurston, Lewis, and Cowlitz Counties of southwest Washington. The play is bounded to the east by volcanic rocks of the Cascade Range or tightly folded and faulted Eocene strata in the Cascade foothills, and to the south, west, and north by uplifts of Eocene volcanic rocks. No recent coalbed gas exploration has been accomplished in the area of this play. The potential for reserves in this play is considered fair to poor, with low coal rank the main limiting factor.

REGION 3–COLORADO PLATEAU AND BASIN AND RANGE

In the Colorado Plateau and Basin and Range Region 3, potential additions to reserves of coalbed gas are estimated for the Uinta, Piceance, and San Juan Basins. Coals are of Upper Cretaceous and Tertiary age. Estimated in-place coalbed gas resources here account for about 28 percent of the U.S. total. This Region, together with the Rocky Mountains and Northern Great Plains Region 4, contain about 80 percent of the in-place coalbed gas resources of the U.S. The San Juan Basin is the most productive coalbed gas basin in the United States.

UINTA-PICEANCE BASIN PROVINCE (020)

UINTA BASIN

By Dudley D. Rice, Thomas M. Finn, and William B. Cashion

The Uinta Basin part of the Uinta-Piceance Basin Province (020) contains three coalbed methane plays: Uinta Basin–Book Cliffs Play (2050), Uinta Basin–Sego Play (2051), and Wasatch Plateau–Emery Play (2052).

Adams and Kirr (1984), Nuccio and others (1992), and Gloyn and Sommer (1993) present information on the geologic controls and coalbed methane potential of the Uinta Basin, eastern Utah and western Colorado.

In the Uinta Basin, potential for coalbed gas occurs in the Book Cliffs and Sego coal fields areas along the south flank of the basin and the Emery coal field area, which is south of the Book Cliffs, east of the Wasatch Plateau, and west of the San Rafael Swell. In these areas, coal beds are well developed and recoverable resources are at depths less than 6,000 ft. The Upper Cretaceous Ferron Sandstone and Mesaverde Group (Blackhawk Formation and Neslen Member of Price River Formation) are the main coal-bearing units.

In the Emery coal field area, the Ferron Sandstone is the coal-bearing interval, and it ranges from 400 to 500 ft in thickness. Thirteen coal beds have been identified, and the net coal thickness is as much as 35 ft. These coals are generally less than 2,000 ft deep and dip gently to the west (3û to 5¡).

In the Book Cliffs coal field, which is located on the south flank of the basin and west of the Green River, the following coal beds, in ascending order, are assigned to the

Blackhawk Formation (400 to 1,300 ft thick) and have coalbed gas potential: Castlegate A, Castlegate B, Castlegate C, Kenilworth, Castlegate D, Castlegate E, Gilson, Fish Creek, Rock Canyon, and Sunnyside. Individual coal beds are as much as 25 ft thick, but the average thickness is 20 ft. The thickest coal beds occur in the lower 500 ft of the Blackhawk and are relatively continuous. The net coal thickness is as much as 68 ft.

In the Sego coal field, which is east of the Green River, 4 major coal zones occur in the younger Neslen Member of the Price River Formation. The coal beds become fewer and thinner in an eastward direction and eventually pinch out into marine shales of the Mancos Shale. As much as 23 ft of coal occur in the Neslen. In both the Book Cliffs and Sego coal fields, coal beds crop out along the border and dip gently (4¡ to 6¡) to the north into the basin. Although depths of burial for these coals are greater than 20,000 ft along the axis of the basin, recoverable coalbed gas resources probably are restricted to depths less than 6,000 ft.

In the prospective areas (less than 6,000 ft depth), the rank of coals in the Ferron, Blackhawk, and Price River ranges from high-volatile C to A bituminous rank and increases with depth of burial. In the deepest part of the basin where depths of burial are greater than 20,000 ft, the rank of Blackhawk coals is probably low-volatile bituminous. In general, the thermal maturity trend follows the structural configuration on the base of the Mesaverde, which indicates that most of the thermal maturation was established prior to structural movement. On flanks of the basin, present-day rank was probably achieved prior to uplift. Some thermogenic gas was probably generated before uplift and erosion in Tertiary time.

In the Book Cliffs coal field, produced coalbed gas from depths of 4,200 to 4,400 ft averages 89 percent methane, 1 percent ethane, and 10 percent CO_2. Conventional reservoirs in nearby gas fields also produce high amounts of CO_2, but the origin is not known. The coals in the current area of production are marginal with respect to thermogenic gas generation. The gas may be thermogenic and (or) a mixture of thermogenic and relatively recent biogenic.

The Uinta Basin is a strongly asymmetric, east-west trending basin and the coalbed gas potential occurs on the gently dipping southern flank. The well-developed system of northwest-southeast trending faults and gilsonite veins probably cuts the coal-bearing Cretaceous rocks. These faults and veins developed along the north and northeast flanks of the Uncompahgre Uplift during late Paleozoic and Mesozoic time and were periodically reactivated. In the Book Cliffs, cleats are reported to be well-developed and two dominant face cleat sets have been identified: northwest and northeast.

Produced water in the Book Cliffs coal field area is moderately saline (TDS content of about 5,500 ppm, mostly bicarbonate). Water production rates are moderate (several hundred barrels per day initially) and the water will probably be injected into deeper Mesaverde sandstones or discharged on the surface after salinity and solids are reduced.

Abundant desorption data, particularly in the Book Cliffs area, indicate that gas contents are as much as 360 Scf/t within 5 mi of the outcrop. The data suggest three interesting relations. First, based on desorbed, lost, and residual gas calculations, more than 90 percent of the gas is probably recoverable when gas contents are greater than 150 Scf/t. When gas contents are less than 150 Scf/t, only 50 percent of the gas can probably be recovered. Second, gas contents generally increase with distance from outcrop and depth, indicating that some degassing has taken place. Third, although gas contents generally increase with depth for all of the samples, the rate of increase varies for different coal beds. Gas contents in coal beds in the lower part of the Blackhawk (Castlegate B and C and Kenilworth) increase at about 10 Scf/t per 100 ft; however, those in the upper part (Castlegate D, Gilson, Rock Canyon, and Sunnyside) increase at only 4.4 Scf/t/ per 100 ft. The explanation for the different rate of gas content increase for the two groups of coal beds is not known. Finally, data indicate that the coals may be undersaturated with respect to gas, probably as a result of degassing along faults or outcrop. Undersaturation has a significant effect on recoverability because of economics associated with depressurization.

In-place coalbed gas resources have been assessed for the Book Cliffs, Emery, Wasatch, and Sego coal fields. The estimates were made for coal beds greater than 4 ft thick, less than 9,000 ft deep, and using average gas contents for a depth range from 1,500 to 3,000 ft. The estimate for these areas ranges from 8 to 11 TCF, with most of resources occurring in Book Cliffs coal field, followed, in descending order, by the Emery, Wasatch, and Sego coal fields. A significant part of this in-place resource may be at depths greater than 6,000 ft where recoverability may be a problem.

On the basis of 1991 tonnage statistics, Utah ranked 13th among States as a producer of coal, and all the production came from underground mines. Most of the production came from the Book Cliffs, Emery, and Wasatch coal fields in Carbon and Emery Counties which ranked 24th and 28th, respectively, in the country in terms of total tonnage. On the basis of 1988 statistics, Utah was 8th among the States for methane emissions related to underground mining. On the basis of 1977 information, most of the gassy mines, those which produce more than 100 MCFPD, are located in the Book Cliffs coal field and only one gassy mine was in the Emery coal field.

Since 1982, coalbed gas has been produced from the Soldier Creek mine in the Book Cliffs coal field. Gas is recovered from horizontal in-mine wells drilled in the Gilson, Rock Canyon, and Sunnyside coal beds. The wells are about 2,000 to 3,000 ft long and more than 300,000 ft of hole has been drilled. Current daily production rate for all wells is 1,500 MCF and cumulative production of 1.5 BCF is reported.

More than 40 vertical coalbed gas wells have been drilled in the basin; most have been completed since the middle of 1992. Existing wells are located in the Book Cliffs and Emery coal fields. In the Drunkards Wash Unit of the Emery coal field, production was established in the spring of 1993 from Ferron coal beds at depths of 1,800–2,100 ft. In the Book Cliffs coal field north of Price, several wells have been completed in Blackhawk coal beds at depths of 4,000–4,400 ft, and production tests were conducted for as much as one year. In both areas, gas production increased as water production decreased over the first few months.

Gas is produced from conventional and low-permeability sandstones in the central and eastern parts of the basin. Consequently, a regional gas pipeline has recently been completed that provides potential coalbed gas producers with an access to Midwest markets. However, localized infrastructure in areas of potential for coalbed gas is needed.

2050. UINTA BASIN–BOOK CLIFFS PLAY,
2051. UINTA BASIN–SEGO PLAY (HYPOTHETICAL),
2052. WASATCH PLATEAU–EMERY PLAY

Target areas for recoverable coalbed gas occur on the south flank and in front of the Wasatch Plateau where coal beds are less than 6,000 ft deep. On the basis of coal resources, gas content, and depth, three plays have been identified and named after the major coal fields in the area: (1) Uinta Basin–Book Cliffs Play, (2) Uinta Basin–Sego Play, and (3) Wasatch Plateau–Emery Play.

In the Uinta Basin–Book Cliffs Play (2050), coal resources of the Blackhawk Formation are significant (net coal thickness as much as 68 ft), gas contents may be as much as 400 Scf/t, and depths extend to 6,000 ft. However, data indicate that coal beds may be undersaturated with respect to gas, which would adversely affect economic production. The extent of this undersaturation is not known. Production has been established in an underground mine, and favorable production rates have been tested in vertical wells. The potential for additional reserves in this play is assessed to be good to fair. Possible regional undersaturation with regard to gas is a limiting factor.

The hypothetical Uinta Basin–Sego Play (2051) covers as large an area as the Book Cliffs Play (2050) because of the low dips, but the coal beds of the Neslen are fewer and thinner. No coalbed wells have been drilled. The potential for reserves of coalbed gas in this play is rated as fair because of the limited coal resources and possible undersaturation.

In the Wasatch Plateau–Emery Play (2052), coal resources in the Ferron Sandstone are significant (net coal thickness as much as 35 ft), and gas contents, at least in the northern part, are similar to the those of the Uinta Basin–Book Cliffs Play (2050). In addition, coal beds are commonly at depths less than 2,000 ft. Economic production of the Drunkards Draw Unit has been established in this play, and the potential for additional reserves in this play is rated as good.

UINTA-PICEANCE BASIN PROVINCE (020)

Piceance Basin

By Ronald C. Johnson, Dudley D. Rice, and Thomas M. Finn

The Piceance Basin part of the Uinta-Piceance Basin Province (020) contains five identified plays: Piceance Basin–White River Dome Play (2053), Piceance Basin–Western Basin Margin Play (2054), Piceance Basin–Grand Hogback Play (2055), Piceance Basin–Divide Creek Anticline Play (2056), and Piceance Basin–Igneous Intrusion Play (2057).

Geologic controls and resource potential of coalbed gas in the Piceance Basin of western Colorado are given by McFall and others (1986b), Reinecke and others (1991), and Tyler and others (1991).

Significant coal deposits are found in the Upper Cretaceous Iles Formation, a marginal marine unit, and in the lower part of the overlying Upper Cretaceous Williams Fork Formation, which is mostly fluvial in origin. The Iles and Williams Fork Formations are both part of the Mesaverde Group. Maximum coal thickness in the Iles Formation is about 18 ft. The major coal resources occur in the Cameo-Fairfield Coal Zone in the lower part of the Williams Fork Formation. The coal-bearing zone is present throughout the basin, except in the southeast corner, and net coal thickness averages 35 ft and is as much as 114 ft. Maximum reported thickness for an individual seam within the Cameo-Fairfield Zone is about 35 ft. Coal beds within the Cameo-Fairfield Zone have been mined at many localities around the margins of the basin and have been the principal target for coalbed gas exploration in the basin. The Cameo-Fairfield Zone extends to depths greater than 23,000 ft, and a large part of the coal resources are at depths greater than 6,000 ft.

Coal rank for the Cameo-Fairfield Zone ranges from subbituminous A to high-volatile A bituminous at the surface to semianthracite along the deep basin trough. In general, coal rank increases with depth from north to south in the basin. In the southeastern part of the basin, intrusions have locally raised the ranks of coal beds exposed at the surface to as high as anthracite. High-quality coking coal has been mined in this intruded area since the early part of the century. Most of the coalbed gas in the basin was probably generated during the period from about 35 to 10 Ma when the basin was under maximum burial conditions. Regional uplift and erosion began about 10 Ma resulting in significant cooling of the entire stratigraphic interval, including the Upper Cretaceous coal beds.

Produced coalbed gases in the Piceance Basin are quite variable in their composition, partly resulting from their variable rank. Heavier hydrocarbon gas content ranges from 0.1 to almost 18 percent and CO_2 content varies from 0 to more than 25 percent. Carbon isotope data indicate that these hydrocarbon gases are of thermogenic origin. In the White River Dome located on the north edge of the basin, wet gas and waxy oil are produced from the coal beds of high-volatile B bituminous rank. The wet gas and oil are interpreted to have been generated from the hydrogen-rich macerals in the coal. These wet gases are also associated with large amounts of CO_2, which resulted from thermal destruction of upper Paleozoic carbonates and (or) from deep-seated igneous activity. In the central part of the basin, the coalbed gases are drier (heavier hydrocarbons less than 5 percent), with smaller amounts of CO_2 (less than 4 percent), and were generated from coals at higher rank.

The Piceance Basin is highly asymmetric with gently dipping southern and western flanks and a near vertical to overturned eastern flank, the Grand Hogback. The White River Dome and the Divide Creek Anticline are structures on the north and southeast parts of the basin, respectively, which probably are underlain by northeast-dipping thrust faults. These two structures are areas of enhanced permeability because of tight folding and faulting.

Several well-developed regional fracture systems occur in the basin and the coal cleat systems seem to parallel these regional patterns. Cleat development can vary markedly between different coal beds in the same area. For example, in the area of Grand Valley-Parachute fields, the cleat system is poorly developed in the lower, thicker coal bed in the Cameo-Fairfield Coal Zone, and this bed is less productive than the thinner beds which overlie it. In general, the basin is characterized by relatively low permeabilities for both coalbed and sandstone reservoirs.

Coal beds of the Mesaverde Group are within a large, low-permeability, basin-center gas accumulation. Rates of water production from both sandstone and coalbed reservoirs within this accumulation are generally quite low. In the Grand Valley-Parachute fields area, coalbed gas wells produce less than 4 bbl of water per day. Some recharge takes place along the elevated and wet southeast and east margins, and to a lesser extent along the southwest and north margins. In the Divide Creek area, initial water production rates are as much as 2,500 bbl of water per day. However, fresh water only extends into the basin for a short distance (less than 10 mi) and underground mines are usually dry.

The pressure regime of Mesaverde coal beds is complex. An area of overpressuring occurs in the east-central part of the basin. This overpressuring is the result of (1) artesian conditions in the Divide Creek Anticline area where permeabilities are higher and relatively fresh water is produced and (2) hydrocarbon generation in the area where temperatures exceed 250¡F. This overpressuring is surrounded by a large area of underpressuring, which was probably an area of previous overpressuring that has cooled.

Gas contents of Mesaverde coals are as much as 600 Scf/t at depths of about 7,000 ft. Pressure-core data indicate that gas contents may be as high as 765 Scf/t at a depth of about 7,100 ft. These values are some of the highest in the country and are a product of both high rank and great depth.

In-place coalbed gas resources have been estimated to range from 84 to 103 TCF. The variability of the resource is the result of the different gas content values that have been reported and used in the basin. However, about two-thirds of the in-place coalbed gas resource in the basin is at depths greater than 5,000 ft. The combination of low permeability and increasing depths will greatly reduce the recoverability of the in-place gas.

At present, only a limited amount of high-quality coking coal is being mined in the southeastern part of the basin where the coal rank has been elevated by igneous intrusions. This intruded area contains some of the gassiest mines in the country with methane emissions as high as 10,500 MCFPD.

The first coalbed gas well was drilled in the basin in 1978. This well produced about 75 MMCF from a depth of about 7,800 to 8,050 until abandoned in 1978. From 1978 until 1987, some activity took place in high-rank coal beds in the southern part of the basin. None of these projects were commercial because of high water productivity.

More recently, coalbed gas activity has focused on the central and northern parts of the basin,. and, currently, five fields are producing: Grand Valley, Parachute, Pinyon Ridge, South Shale Ridge, and White River. The first commercial production was achieved in the Grand Valley and Parachute fields in the central part of the basin where 51 coalbed gas wells were completed between 1989 and 1992. Forty-two of the wells were also completed in adjacent low-permeability sandstone reservoirs of the Mesaverde Group.

Coal beds in this area are characterized by high rank (low-volatile bituminous) and low permeability. Some coalbed gas wells were completed to depths as much as 8,400 ft, the deepest production to date. These coalbed gas wells were probably commercial only because of the tax credit and the commingling of the coalbed gas with that of adjacent conventional reservoirs.

The White River Dome area contains the best commercial production of coalbed gas established in the basin (White River and Pinyon Ridge fields). Depth of production extends to about 7,500 ft, but the rank of the coal is lower (high-volatile B bituminous), and permeability is higher than in the central part of the basin. In this area, waxy oil is produced along with wet gas, and large amounts of CO_2 (as much as 30 percent) and water. The higher permeability, which is not characteristic of the basin as a whole, is probably the result of folding and faulting.

In 1992, 95 coalbed gas wells in the basin produced about 3.2 BCFG for an average of about 95 MCFPD per well. Considering the large in-place coalbed gas resources in the basin, these production statistics are low and suggest that permeability may be a major obstacle to large-scale commercial development.

Large resources of gas, both conventional and unconventional, are estimated for the Piceance Basin. However, the development of these resources has been somewhat hampered by the availability of pipelines that are mainly intrastate. Recently, this situation has improved and the development of coalbed gas should take place if technology problems, mostly related to low permeability, can be overcome.

2053. PICEANCE BASIN–WHITE RIVER DOME PLAY,
2054. PICEANCE BASIN–WESTERN BASIN MARGIN PLAY,
2055. PICEANCE BASIN–GRAND HOGBACK PLAY (HYPOTHETICAL),
2056. PICEANCE BASIN–DIVIDE CREEK ANTICLINE PLAY,
2057. PICEANCE BASIN–IGNEOUS INTRUSION PLAY (HYPOTHETICAL)

The Piceance Basin is divided into five coalbed gas plays: (1) Piceance Basin–White River Dome Play, (2) Piceance Basin–Western Basin-Margin Play, (3) Piceance Basin–Grand Hogback Play, (4) Piceance Basin–Divide Creek Anticline Play, and (5) Piceance Basin–Igneous Intrusion Play. The potential is mainly in coal beds of the Cameo-Fairfield Zone, which extend from depths of 500 ft to 6,000 ft. Because of the depth limitation, large parts of the in-place gas resource probably will not be recoverable.

The Piceance Basin–White River Dome Play (2053) extends along the northeastern flank of the basin and includes the southeast-plunging White River Dome and a small anticlinal nose north of the dome. The White River and Pinyon Ridge fields are in this play and the production rates (as much as 400 MCFPD per well) are the best in the basin because of enhanced permeability due to folding and faulting. Potential for additional reserves in this play is considered to be good, although production will be probably be characterized by large amounts of water and CO_2.

The Piceance Basin–Western Basin Margin Play (2054) extends along the entire western flank of the basin and includes production from the Grand Valley, South Shale Ridge, and Parachute fields. Along the Colorado River, the limit of the play is extended to a depth of about 7,000 ft because of existing production in Grand Valley field. The gas production rates (less than 100 MCFPD) are much lower than at White River Dome Play and only minor amounts of water (less than 4 bbls per day per well) are produced. This is largest play area in the basin, but its potential for additional coalbed gas reserves is considered to be fair because of low permeability.

The Piceance Basin–Grand Hogback Play (2055) is a hypothetical play that extends along most of the eastern margin of the basin where dips vary from about 45¡ to overturned. Because of the steep dips, the coal beds reach a depth of 6,000 ft in a short distance from the outcrop. Only a few coalbed gas wells have been drilled in this play and, although significant gas shows were reported, no commercial production has been established. Potential for reserves in this play is rated as fair to poor based on structural complexity and limited extent of the play area.

The Piceance Basin–Divide Creek Anticline Play (2056) includes the Divide Creek, Wolf Creek, and Coal Basin anticlines in the southeastern part of the basin. The coal beds are gassy as indicated by coal mines in the Coal Basin Anticline, but severe water problems have plagued attempts to produce coalbed gas in this area. The potential for reserves of coalbed gas is fair to poor based on previous high production rates of water.

The Piceance Basin–Igneous Intrusion Play (2057) in the southern part of the basin contains the highest coal ranks (anthracite) in the basin. The intrusions are mainly laccolithic, and in some cases coal has been mined beneath them. The area is highly dissected by tributary systems of the Gunnison River. As a result, the coal-bearing interval is exposed throughout the play area. Although the high coal ranks are favorable for coalbed gas generation, the shallow depths and proximity to outcrop indicate that much of the gas may have naturally desorbed. Potential for reserves of coalbed gas is considered to be poor with shallow burial depths as a major restricting factor.

SAN JUAN BASIN PROVINCE (022)

By Dudley D. Rice and Thomas M. Finn

Geologic and hydrologic controls and resource potential of coalbed gas in the San Juan Basin, northwestern New Mexico and southwestern Colorado are given by Kelso and others (1988), Crist and others (1990), Ayers and others (1991), and Ayers and Kaiser (1992). The effects of coal reservoir properties on productivity as determined by reservoir simulation are reported by Paul and Young (1993).

In the San Juan Basin, significant resources of both coal and coalbed gas are in the Upper Cretaceous Fruitland Formation. The occurrence, thickness, and geometry of Fruitland coal deposits are strongly influenced by depositional environment. Coal deposits resulted from peat that accumulated on sandstone platforms of the underlying Pictured Cliffs Sandstone, which were deposited along the coast of a northeast-prograding shoreline. Individual coal beds are as much as 40 ft thick. The greatest net coal thickness, up to 100 ft, is in a northwest-trending belt in the northern part of the basin where thick coal deposits occur in both northwest- and northeast-trending deposits, with the thickest deposits in the northwest-trend. In the northwest-trend, individual coal beds average more than 9 ft in thickness, which resulted from standstills in the Pictured Cliffs Sandstone shoreline. Average thickness of coal beds in the northeast-trend is 6 ft. They occur in floodplain facies between channel-fill sandstone deposits. Depths of burial for the Fruitland coal beds are as much as 4,200 ft in the northeastern part of the basin.

Coal beds in the Upper Cretaceous Menefee Formation are an additional target for gas. The Menefee is older and deeper than the Fruitland and is in the middle part of the Mesaverde Group. Although as much as 35 net ft of coal occur in the Menefee, the coals are generally thinner, more discontinuous, and dispersed over a greater stratigraphic interval than those of the overlying Fruitland Formation. The Menefee coals are as deep as 6,500 ft.

Across the central basin, the rank of Fruitland coal increases northeastward from subbituminous C to medium-volatile bituminous. Coal rank generally conforms with the structural configuration of the basin and abruptly decreases along the steeply dipping north flank. Rank trends for Menefee coals are similar, but somewhat higher because of greater burial depth. Present-day depths of burial do not coincide with the maximum levels of thermal maturity in the northern part of the basin. This is partly the result of significant uplift and erosion that has taken place since about 10 Ma. However, maximum depth of burial and present-day heat flow cannot account for the high rank present at the north end of the basin. In addition to maximum burial depths, this high rank is interpreted to be the result of (1) convective heat transfer associated with a deeply buried heat source located directly below the northern part of the basin, and (or) (2) the circulation of relatively hot fluids into the basin from a heat source located in the vicinity of the San Juan Mountains to the north. Thermogenic gases were probably generated in the coals during time of maximum heat flow and (or) depth of burial in Tertiary time.

Produced Fruitland coalbed gases are variable in their composition. Although methane is the major component, significant amounts of heavier hydrocarbon gases (as much as 23 percent), CO_2 (as much as 13 percent), and nitrogen (as much as 11 percent) are also present. The producing part of the basin can be divided into two areas based on coalbed gas composition. The boundary between the two areas is rather abrupt and coincides with the structural hingeline, which is discussed later. In the southern part, the gases are generally wet (heavier hydrocarbons generally greater than 6 percent) with minor amounts of CO_2 (generally less than 1 percent). Waxy oil is produced in association with wet gases in this part. In contrast, gases in the north part are dry (heavier hydrocarbons generally less than 3 percent) but contain significant amounts of CO_2 (generally greater than 6 percent). On the basis of chemical and isotopic composition, the hydrocarbon gases are interpreted to be mainly thermogenic in origin. The heavier hydrocarbon gases and oils, which are restricted to coals of high-volatile B bituminous and lower ranks, were probably generated from hydrogen-rich coals. In the northern part of the basin, active groundwater flow has probably led, relatively recently, to intensified microbial activity resulting in aerobic consumption of the heavier hydrocarbons and mixing of biogenic methane-rich gas. Isotopic data suggest that the large amounts of CO_2 in the north part of the basin are also the result of recent bacterial activity.

The San Juan Basin is a strongly asymmetric basin with a gently dipping southern flank and steeply dipping northern flank. It has two axes in the northeastern part of the basin, which are separated by the Ignacio Anticline. A structural hingeline has been interpreted to occur where the gently dipping southern monocline meets the basin floor. This hingeline is probably a zone of northwest trending, en-echelon normal faults and divides the basin into two distinct areas relative to coalbed gas productivity.

The Colorado-New Mexico border roughly marks the division of the basin into two areas of distinctly different face-cleat orientations. North of the border the cleats are oriented northwestward; however, south of the border they are oriented northward or northeastward. Along the State border, interference of the two sets may result in increased permeability, which has lead to the success of vertical open-hole cavity completions. Increased permeability may also result from compaction-induced fractures in areas where the Fruitland coal beds overlie upper Pictured Cliffs sandstone tongues. In addition, compaction-induced fractures may be present where coal beds split and interfinger with fluvial channel-sandstones. In the Cedar Hill coal field area of northern New Mexico, multicomponent 3D seismic surveys indicate that movement on basement-controlled faults with strike-slip displacement has opened natural fractures in the coal.

Fruitland coal beds are major aquifers in the San Juan Basin. In the northern part of the basin, they are commonly thick, well cleated, and more permeable than the adjacent sandstones that serve as aquitards. Recharge is mainly along the wet, northern margin of the basin in the foothills of the San Juan Mountains with limited recharge along the other margins. A sharp steepening of the potentiometric surface occurs along the structural hingeline and divides the basin into two hydrologic provinces. This steepening indicates an area of reduced permeability and is a no-flow boundary.

Groundwater movement and associated reservoir characteristics can be tracked by water composition, in particular the chloride content. Lobes of relatively fresh, low-chloride water extend into the basin from the northern margin. The hydrochemical boundary between low chloride, $NaHCO_3$-type water and high chloride NaCl-type water coincides with the structural hingeline. Water production rates for individual wells are highly variable and range from essentially nothing to more than 2,000 barrels per day. The production rates are strongly controlled by hydrodynamics, and the highest rates are north of the hingeline and along the northern margin. Most of the water is currently being injected into deep wells. However, the disposal capacity is rapidly being approached and alternate, cost-effective methods of disposal will be required.

The Fruitland coal beds are both abnormally pressured and underpressured relative to fresh-water hydrostatic pressure. Overpressuring occurs in north-central part of the basin and coincides with the area of relatively fresh water. The overpressuring is interpreted to be artesian in origin as evidenced by the flowing artesian coalbed gas wells. However, most of the basin is underpressured. The transition from overpressured to underpressured is abrupt and takes place along the structural hingeline.

Gas contents in the San Juan Basin are highly variable and range from less than 100 to more than 800 Scf/t. As expected, there is a general relation between gas content, depth, and rank. However, the gas content also strongly correlates with the pressure regime. In dealing with coals of similar rank, the highest gas contents are usually reported from the overpressured north-central part of the basin.

On the basis of resources and a range of gas contents, in-place coalbed gas resources of the Fruitland Formation are estimated to be about 50 TCF. An additional 38 TCF have been estimated for the Menefee coal beds resulting in a total of 88 TCF for the basin.

New Mexico ranked 14th among the States in 1991 for the production of coal. Most of this coal was mined on the surface from the Fruitland along the western flank of the basin. The New Mexico counties of San Juan and McKinley, located on the west flank of the basin, were ranked 7th and 10th in the nation in terms of production from surface mining. Some coal is also mined in the Colorado part of the basin. Because the coal in the basin is mostly mined on the surface, methane emissions are minor.

The San Juan Basin has been the most productive coalbed gas basin in the United States since 1988. In 1992, more than 436 BCF of coalbed gas were produced from about 2,000 wells. In 1993, more than 480 BCF were produced from about 1980 wells in only the New Mexico part of the basin. Most of the coalbed gas wells in the basin have been drilled since 1987 and the largest number was completed in 1990. Although the Black Warrior Basin has the largest number of producing wells, more than four times as much coalbed gas was produced in the San Juan Basin in 1992 (436 BCF versus 92 BCF). Production rates for individual wells are highly variable and range from 50 to 15,000 MCFPD. About one-third of the total producing wells are vertical open-hole cavity wells, which accounted for about 75 percent of the gas production in 1992. These cavity wells commonly produce 10 times more gas than those completed by hydraulic fracturing. However, successful, open-hole cavity completions are generally restricted to a northwest-trending area referred to as the “fairway,” located north of the structural hingeline. Cavity wells in the “fairway” are successful because of artesian overpressuring and high permeability; open-hole cavity completions have not been successful in other basins.

The first coalbed gas well (Cahn No. 1) was drilled in the New Mexico part of the basin in late 1970's. The well is part of the Cedar Hills coal field. Most of the production in New Mexico is assigned to the Basin Fruitland coal field, and all the production in Colorado is assigned to the Ignacio-Blanco coal field. The reserves in the basin as of 1993 are about 7.8 TCF, which represents about 70 percent of the coalbed gas reserves in the country.

The San Juan Basin has had major gas pipelines to southern California since the 1950's when gas was first produced from Cretaceous sandstones. With the rapid development of coalbed gas, pipeline capacity was insufficient in the late 1980's. Since 1990, major expansion projects have resulted in increased capacity for transmitting the gas to interstate markets.

2250. SAN JUAN BASIN–OVERPRESSURED PLAY,
2252. SAN JUAN BASIN–UNDERPRESSURED DISCHARGE PLAY,
2253. SAN JUAN BASIN–UNDERPRESSURED PLAY

The potential for additional reserves of Fruitland coalbed gas is generally situated where the coal beds are deeper than 500 ft, although some production has been established at shallower depths.

On the basis of hydrology, pressure regime, reservoir properties, and hydrocarbon composition, three plays are identified for the Fruitland coalbed gas: (1) San Juan–Overpressured Play (2250), (2) San Juan--Underpressured Discharge Play (2252), and (3) San Juan–Underpressured Play (2253). The San Juan–Overpressured Play (2250) is in the north-central part of the basin and north of the structural hingeline where recharge of relatively fresh water takes place. The coals are generally thick (>10 ft) and laterally extensive in northwest-trending bands. The coals are generally of high rank (as much as medium-volatile bituminous), have high gas contents, and are characterized by high formation pressures (greater than 0.5 psi). The coalbed gases are relatively dry (heavier hydrocarbons less than 3 percent) with significant amounts of CO_2 (between 3 and 12 percent). Although depths of burial extend to 4,200 ft, the Fruitland Coal in a large part of the play is at depths less than 3,000 ft. Within this play is the very productive "fairway" trend. The average daily gas production rates for wells in this play during their most productive year range from less than 30 to more than 3,000 MCFPD with the highest rates in the "fairway" trend. Because of recharge of fresh water on the north margin, most wells produce water at rates as high as 2,000 bbl per day and must be dewatered to initiate desorption and production. Because of the high productive capacity of wells in this play, the prime areas have been explored and developed (Cedar Hills, Ignacio-Blanco, and Basin Fruitland coal fields). The potential for additional reserves from this play is considered to be good. However, the areal extent of this potential is limited because of previous development.

The San Juan–Underpressured Discharge Play (2252) is located south of the structural hingeline in the southwest part of the basin where the coal beds are underpressured (0.3 to 0.4 psi). The area is characterized by regional groundwater convergence and discharge. The groundwater is a NaCl-type and has a higher chloride content than that of the overpressured play. Coals may be as much as 10 ft thick and the thickest coals occur in northeast trends. Compared to the overpressured play, coal rank is lower (high-volatile B bituminous and lower) and gas contents are lower. The gas is chemically wet (heavier hydrocarbons generally more than 5 percent) with less than 1.5 percent CO_2. During early months of production, the coals of high-volatile B bituminous rank produce some waxy oil. Depths of burial are less than 3,000 ft, and production is commonly water free. The average daily production of wells in this play during their most productive year ranges from 30 to 300 MCFPD. The potential for undiscovered coalbed gas in this play is estimated to be good to fair. Similar to the overpressured play, extensive drilling and production (Basin Fruitland coalbed gas field) have taken place in this play, and the remaining potential for reserves is mainly at shallower depths (less than 1,500 ft) in the southwestern part of the play.

The San Juan–Underpressured Play (2253) is located in the eastern part of the basin where groundwater flow is sluggish. The produced waters are a NaCl-type and resemble seawater. Coal beds are generally thin and gas content is low, particularly in the eastern part. Minor production has been established and rates are low (average annual production in the range of 1 to 3 MMCF) with little or no water production. Depths of burial (500–4,000 ft) and coal rank (subbituminous to medium-volatile bituminous) are variable and generally increase to the north. The potential for additional reserves from this play is only fair because of underpressuring and low permeability.

REGION 4–ROCKY MOUNTAINS AND NORTHERN GREAT PLAINS

In the Rocky Mountains and Northern Great Plains Region, recoverable coalbed gas resources are estimated for the Powder River, Wind River, Greater Green River, and Raton Basins. These basins have enormous resources of Cretaceous and Tertiary coal and associated coalbed gas. Wyoming was the top coal producing state in 1991, and most of the production came from surface mining in the Powder River Basin. In-place coalbed gas resources of these basins represent about 52 percent of those calculated for the country, with most of these (87 percent) being in the Greater Green River Basin. Although the in-place resources of coalbed gas are large, their economic recoverability remains questionable.

POWDER RIVER BASIN (033)

By Dudley D. Rice and Thomas M. Finn

Two plays are identified in the Powder River Basin, Powder River Basin–Shallow Mining-Related Play (3350) and Powder River Basin–Central Basin Play (3351).

The coalbed gas potential of the Powder River Basin of northeastern Wyoming and southeastern Montana is evaluated by Law and others (1991) and Tyler and others (1991). The hydrologic effects of surface coal mining, which might affect coalbed gas production, are given by Martin and others (1988).

The Tongue River, the upper member of the Paleocene Fort Union Formation, is the main coal-bearing unit in the Powder River Basin. The Tongue River, which was deposited in fluvial and lacustrine environments, is as much as 1,700 ft thick and contains 8 to 10 coal beds. The coal beds can be anomalously thick and range from less than 5 ft to more than 190 ft in thickness. Some of the thicker, more laterally continuous coal beds are commonly 20 to 90 ft thick. Because of the size of the basin and the thickness of the coal beds, the basin contains large resources of coal (as much as 1.3 trillion short tons). Some of the thicker seams are correlatable over large areas and are referred to as the Anderson-Dietz, Wyodak-Anderson, and Big George-Sussex. They were deposited in mires associated with meandering and anastomosing rivers. The coals in the basin occur at depths less than 2,500 ft.

The rank of coal in the Fort Union Formation is low over the entire basin, ranging from lignite to subbituminous B. These are the lowest rank coals in the United States from which commercial production has been established. The level of thermal maturity is also low in the underlying Upper Cretaceous shales indicating a relatively low geothermal gradient for the basin. As much as 2,000 ft of overburden was probably removed about 10 Ma, so that the Tertiary coals were never buried deeper than 4,500 ft.

Natural gas produced from the Fort Union coals is composed mostly of methane with minor amounts of ethane (average 0.2 percent) and carbon dioxide (average 0.5 percent). The gases are interpreted to be biogenic, based on carbon isotope analyses, but the timing of the gas generation is questionable. Biogenic gas was undoubtedly generated and accumulated shortly after deposition of the peat during a time of rapid subsidence and deposition. However, some of this early-formed gas probably degassed following uplift and erosion about 10 Ma and earlier along the flanks as the basin was forming. Relatively recent groundwater flow in the basin also probably lead to generation of biogenic gas, particularly along the flanks of the basin. However, the widespread generation of late-stage biogenic gas generation in association with groundwater flow is uncertain because of the discontinuous nature of the coal beds.

The Powder River is a very large intermontane structural basin; the axis is along the west side. Dips of Tertiary strata on the broad eastern flank are gentle (average 1 to 2¡), whereas those on the western flank are steeper (average 5 to 25¡). Along the shallow eastern flank of the basin, the coals are deformed in an area where the structure, as indicated by deeper Cretaceous units, is a gently dipping, homoclinal slope. These deformational features, which are small-scale folds and faults, are interpreted to be penecontemporaneous compaction structures that formed in response to rapid facies changes associated with the fluvial and lacustrine depositional environments. Although these compaction structures have only been identified on the shallow eastern flank, they should be widespread in the basin.

Face cleats in the Tongue River coals are generally normal to bedding and generally strike in an easterly direction. The average spacing of the cleats as measured in a mine ranges from about 3 to 5 in. This spacing probably would be closer in higher rank coals. Because of the different stress fields associated with compaction folding and faulting, the orientation and spacing of the cleats may vary over short distances.

The Tongue River coals are major aquifers in the Powder River Basin. In general, groundwater flows to the northwest from the east side of the basin. Artesian conditions are developed within the basin where the coal beds are discontinuous and confined by shales. Flowing water wells resulting from these artesian conditions are common in the

Tongue and Powder River valleys. The water from both shallow producing wells and several mines is relatively fresh (TDS less than 1,300 ppm) and can be surface discharged. However, the large volume of water from the thick, permeable coal beds may create erosional problems. In addition, possible depletion of shallow aquifers and (or) contamination by gas escaping from dewatered coal seams are concerns. Sandstones overlying the coal beds are used as aquifers. If communication does exist, the sandstone aquifers may be depleted by coal dewatering associated with coalbed gas production.

As a result of low rank and shallow depths, gas contents of the Tertiary are low (less than 75 Scf/t), and the coals may be undersaturated with respect to gas. However, because of the large resources of coal, the in-place gas resources in the basin have been estimated to be as much as 30 TCF using an average gas content of 25 Scf/t.

The Powder River Basin is a major coal-producing province because of the occurrence of relatively thick, low-sulfur coals at shallow depths. The coal is mined entirely on the surface in both Wyoming and Montana. On the basis of 1991 tonnage figures, Campbell County, Wyoming, which is on the shallow eastern flank, is first in the country for both total coal production and coal production from surface mining. Because of the low gas contents and the fact that all coal is mined on the surface, methane emissions are considered to be minimal in the basin.

More than 250 coalbed gas wells have been drilled in the basin. Although some wells have been drilled to more than 1,000 ft in the deeper part of the basin, most of the wells are located on the shallow eastern flank and close to active surface mines. The dewatering operation at the mines has probably lowered the water table of coal beds in the nearby wells. In 1992, 29 wells produced about 1 BCF of coalbed gas from the Rawhide Butte and Maysdorf fields. The average depth of production in these fields is about 500 ft and daily production from individual wells is less than 100 MCFPD. In the Rawhide Butte field, pressure gradients range from 0.26 to 0.29 psi/ft. These values indicate underpressuring that might be the result of dewatering in adjacent coal mines. In addition, there has been development of gas from adjoining sandstones where gas was generated in and migrated from adjoining coal beds.

In the Hartzog oil field, several shallow coalbed gas wells have been drilled. The produced water will be used for waterflooding and the coalbed gas for lease operations.

The Powder River Basin is primarily an oil-prone basin with an extensive infrastructure for oil development. The coalbed gas development to date has been controlled partially by the proximity of low-pressure gas pipelines and future development will depend on an expanded infrastructure for natural gas.

3350. POWDER RIVER BASIN–SHALLOW MINING-RELATED PLAY
3351. POWDER RIVER BASIN–CENTRAL BASIN PLAY

The target area for coalbed gas in the Powder River Basin is where the Tertiary coal beds are generally deeper than 500 ft; it covers the whole basin. Within the target area, two plays have been identified: Powder River Basin–Shallow Mining-Related Play (3350) and Powder River Basin–Central Basin Play (3351).

The Powder River Basin–Shallow Mining-Related Play (3350) is adjacent to active or anticipated coal mines. One large area extends along the eastern flank, and another smaller area is in the northwestern part of basin. This play extends from the downdip limits of active or anticipated mines to the boundary where 5 ft or more of water level decline in the Fort Union coal beds is expected because of surface coal mining. The two currently producing fields (Rawhide Butte and Maysdorf) are located within this play. The potential for additional reserves from this play is regarded as good to fair and is limited by low gas contents. The best potential is on structural highs where a free gas cap probably occurs. Off structure, the gas will probably be produced in conjunction with large amounts of water.

The Powder River Basin–Central Basin Play (3351) coincides with the rest of the basin where the Fort Union coal beds are deeper than 500 ft. It differs in location from the Shallow Mining-Related Play (3350) in that it is not adjacent to active or anticipated coal mines. Sparse data indicate that the gas contents, because of low rank, may not be significantly higher with increasing depth. Although some wells have been drilled in this play, no commercial production has been established. The potential for reserves from this play is assessed to be fair to poor. The coals may be undersaturated with respect to gas, and large amounts of groundwater are present in the cleat systems.

WIND RIVER BASIN PROVINCE (035)

By Ronald C. Johnson and Dudley D. Rice

One play, the Wind River Basin–Mesaverde Play has been identified in the Wind River Basin Province.

The coalbed gas potential of the Wind River Basin, central Wyoming has been evaluated by Rieke and Kirr (1984) and Johnson and others (1993). The work by Johnson and others (1993) is restricted to the Wind River Indian Reservation, which occupies part of the Wind River Basin.

In the basin, significant coal deposits are in the Upper Cretaceous Mesaverde and Meeteetse Formations and Paleocene Fort Union Formation. In a north-south trending belt in the west-central part of the basin, the cumulative thickness of Mesaverde coal, in beds 2 ft or thicker, is as much as 100 ft. East and west of this trend, the total thickness of Mesaverde coal thins to less than 20 ft. The Meeteetse Formation contains coal throughout the basin, but the cumulative thickness, in beds 2 ft or thicker, is generally less than 20 ft. However, as much as 40 ft of Meeteetse coal has been identified in the west-central part of the basin, near the thickest occurrence of coals in the underlying Mesaverde. The Fort Union Formation contains significant coal resources in a broad area along the southern flank of the basin. Cumulative thicknesses of as much as 100 ft of Fort Union coal, in beds 2 ft or thicker, occur in two areas in the western and central parts of the basin.

The rank of Mesaverde and Meeteetse coal beds varies from lignite at or near the surface to anthracite at depths of more than 18,000 ft along the deep-basin trough. The rank of Fort Union coal beds ranges from subbituminous C near the surface to high-volatile A bituminous at a depth of 11,000 ft. Thermogenic coalbed gas was probably generated while the basin was under maximum aggradation, about 35–10 Ma.

The coalbed gases consist mainly of methane, but also contain variable amounts of heavier hydrocarbon gases (as much as 4.6 percent) and CO_2 (as much as 6.5 percent). Isotopic data indicate that the gases are a complex mixture of biogenic and thermogenic origin.

The Wind River Basin is a structural and sedimentary basin that is narrow and deep. The basin is more than 170 mi long, but only 60 mi wide at its widest place. The coal-bearing interval, which crops out along the western and southwestern flanks of the basin, plunges to depths greater than 19,000 ft in a distance less than 5 mi. These steep dips limit the area where coal beds occur at depths favorable for recovery of coalbed gas (less than 6,000 ft). The basin contains numerous anticlinal structures, and limited information suggests that these structures may have enhanced cleat systems in the coal.

Gas contents of as much as 115 Scf/t have been measured to depths of 1,000 ft. However, no information is available on gas content at greater depths. Earlier work indicated that about 2.2 TCF of in-place coalbed gas resources may be present in the basin. Recent work in the Wind River Indian Reservation suggests a resource base of as much as 6 TCF for Mesaverde coal beds to depths of 9,000 ft.

Minor amounts of coal have been produced at several localities in the western part of the basin. No mining activity is currently taking place.

In 1990, a gas well completed in a deeper zone was recompleted in Mesaverde coal beds at depths of about 3,200 to 3,840 ft. The well is located on the Riverton Dome in the southwest part of the basin. The well produced as much as 233 MCFPD and was shut in after producing about 45 MMCFG and 52,000 bbl of water. This is the only known coalbed gas well in the basin. The Wind River Basin is a major gas-producing basin and the basic infrastructure is in place for the development of coalbed gas.

3550. WIND RIVER–MESAVERDE PLAY

The best potential for reserves of coalbed gas in the Wind River Basin is from Mesaverde coal beds. The Meeteetse coals are generally too thin, but multiple-seam completions with Mesaverde coals may be possible in areas where coals in both formations are thick. Fort Union coals are not considered to be prospective because of their low rank and anticipated low gas contents, although data are not available. One coalbed gas play is identified, the Wind River-Mesaverde Play (3550), and it occurs in the southwestern part of the basin where the Mesaverde coal beds are (1) at depths of 300 to 6,000 ft, and (2) at least 20 ft thick, but generally in the range of 30 to 50 ft thick. This is the area where coalbed gas has been produced from one well. The potential for reserves of coalbed gas for this play is estimated to be fair to poor because the coals probably have low gas contents at significant depths. However, not much information is available on the coals at depths greater than 1,000 ft.

SOUTHWESTERN WYOMING PROVINCE (037)

By B. E. Law

The Southwestern Wyoming Province contains major coal resources. Kaiser (1993) has estimated the coal resources in Cretaceous and Tertiary rocks at 1,276 billion tons. The estimate of gas contained in these coal beds is 314 TCF (Kaiser, 1993). For purposes of the assessment of coalbed gas, the six coal-bearing intervals are treated as plays, from oldest to youngest: the Greater Green River–Rock Springs Play (3750), Greater Green River–Iles Play (3751), Greater Green River–Williams Fork Play (3752), Greater Green River–Almond Play (3753), Greater Green River–Lance Play (3754), and Greater Green River–Fort Union Play (3755).

The Southwestern Wyoming Province, also known as the Greater Green River Basin of Wyoming, Colorado, and Utah, is located in the Rocky Mountain foreland and encompasses an area of about 20,000 sq mi. It is a composite of five smaller basins in Wyoming, Colorado, and Utah that includes the Hoback, Green River, Great Divide, Washakie, and Sand Wash Basins. The structural and stratigraphic framework of the region are summarized by Ryder (1988). Notable studies concerning the coalbed methane resources of the region include those by Boreck and others (1981), McCord (1984), Kelso and others (1991), Kaiser and others (1993), Hamilton, (1993), and Kaiser (1993). Other relevant studies include those by Law (1984), Pawlewicz and others (1986), Merewether and others (1987), MacGowan and others (1992), and Garcia-Gonzalez and others (1993).

Coal has been mined for many years in the Southwestern Wyoming Province (037). In the vicinity of the Rock Springs Uplift, coal has been mined from the Upper Cretaceous Rock Springs and Almond Formations, and the Paleocene Fort Union Formation. Currently, coal is mined from the Almond and Fort Union Formations in surface mines on the southeast and northeast flank of the Rock Springs Uplift, respectively, and from the Rock Springs Formation in subsurface mines on the west flank of the uplift. In the Sand Wash Basin, coal has been mined from the Upper Cretaceous Williams Fork and Almond Formations, and from the Paleocene Fort Union Formation at several surface and subsurface mines. Currently, most coal is mined from the Williams Fork Formation in surface mines in the Craig and Meeker areas of Colorado.

Coal beds in these Cretaceous and Tertiary rocks were deposited in environments that include fluvial, delta-plain, and back-barrier depositional systems. The thicker and more continuous coal beds occur in intervals or zones 100–1,200 ft thick. As many as 30 coal beds occur in any single coal zone, but more commonly there are 4 to 8 coal beds. Individual coal beds are generally discontinuous, although coal zones can be traced along outcrops and in the subsurface for many miles. Individual coal beds are as thick as 50 feet. The present-day, maximum depth of burial of the coal zones is about 18,000 ft. For purposes of estimating recoverable gas from coal beds, however, only coal beds buried less than 6,000 ft are considered.

Within the depth constraints of this assessment, the rank of coal beds in the various coal zones ranges from sub-bituminous B to high volatile bituminous B (0.45 - 0.75 percent R_o). The coal is composed of a humic-type organic matter; vitrinite is the main coal maceral. Cleat development is good and is considered normal for sub-bituminous and bituminous coal. The gas content of the coal ranges from less than 100 Scf/t to 541 Scf/t, and the gas typically has large amounts of methane with lesser amounts of ethane and heavier hydrocarbons. Carbon dioxide is present in amounts up to 25 percent.

Exploration activity for coalbed methane in the Southwestern Wyoming Province (037) has been low to moderate. Most drilling activity has focused on the Rock Springs Formation around the northern flanks of the Rock Springs Uplift and the Williams Fork and Almond Formations in the southeast part of the Sand Wash Basin. The presence of large amounts of water in the coal has been the largest obstacle to economic production of gas. Attempts to dewater the coals to levels at which economic rates of gas production may occur have been unsuccessful. Environmental problems related to water disposal have also been obstacles to gas production. The generally low gas content associated with the low rank coals in the play areas, coupled with high water content, indicates that the occurrence of producible coalbed methane in this region is different from that in the San Juan and Black Warrior Basins.

Despite these problems, there remains a good potential for gas production in the province. The areas that have the highest potential for gas production are those areas where coalbed water can be effectively drawn down to levels at which economic rates of gas can be produced. Prospective areas might include the crests of folds where gas has accumulated by buoyancy, sites where the flow of water through coal beds is impeded by the presence of faults, or near mining operations that have lowered the water table in coal. It seems clear, that to be successful in this region, an exploration strategy must be developed that recognizes the need to locate those areas where coal beds may be successfully dewatered.

3750. GREATER GREEN RIVER BASIN–ROCK SPRINGS PLAY

Coal beds in the Upper Cretaceous Rock Springs Formation of the Mesaverde Group are the objective of this play. The play encompasses an area of about 400 sq mi on the northeast, north, and west flanks of the Rock Springs Uplift, near the center of the Southwestern Wyoming Province (037). The coal beds in the Rock Springs Formation were deposited in deltaic environments along a northeast-trending shoreline; the southeast edge of the play boundary marks the edge of this shoreline. The coal-bearing interval is as thick as 400 ft and contains from 1 to 12 coal beds. Cumulative thickness of coal beds within the Rock Springs is commonly 25-100 ft. Individual coal beds range in thickness from 2 to 15 ft and have been mined at several localities on the northern end of the uplift.

Coal rank ranges from sub-bituminous B to high volatile bituminous B (0.45 - 0.74 percent R_o). The coals are of a humic type, composed mostly of vitrinite. Ash content ranges from 5 to 25 percent. Face and butt cleats are well developed and face cleats strike in east-northeast to northeast directions.

Gas content from core and drill-cutting samples of coal as measured by the direct method, are as high as 541 Scf/t. Most samples are less than 150 Scf/t. Gas content in samples collected from coal beds in the Rock Springs decrease with depth, unlike the relationship between gas content and depth in most basins. The reasons for this anomalous condition are not known.

The potential for reserves from this play is low to moderate. Six (6) wells have evaluated the coalbed methane potential of the Rock Springs Formation in the play area and were abandoned due to water disposal problems.

3751. GREATER GREEN RIVER BASIN–ILES PLAY

This play includes coals within the Upper Cretaceous Iles Formation. The play encompasses an area of about 1,050 sq mi located in the southeastern part of the Sand Wash Basin of Colorado and along the eastern edge of the Washakie Basin in Wyoming. The Iles coal zone contains up to 7 coal beds with an aggregate thickness of as much as 50 ft. Individual coal beds are as thick as 15 ft.

Coal beds in the Iles were deposited in a deltaic environment. On the basis of depositional environments similar to that of coals in the Rock Springs and Williams

Fork Formations, the coal beds in the Iles are most likely a humic type and composed mainly of vitrinite. Thermal maturity ranges from 0.45 to 0.7 percent R_o.

This play is immaturely explored and has not been tested.

3752. GREATER GREEN RIVER BASIN–WILLIAMS FORK PLAY

The play area encompasses an area of about 650 sq mi in the southeastern part of the Sand Wash Basin in Colorado. There are two coal zones within the Williams Fork Formation; an upper zone containing as many as 12 coal beds and a lower zone containing as many as 18 coal beds. The aggregate thickness of coals in both zones is as much as 220 ft. Individual coal beds are as thick as 45 ft. Coal beds within the Williams Fork Formation are the principal coalbed gas objectives in the Southwestern Wyoming Province (037).

Although there are no maceral analyses available for Williams Fork coals, they are most likely similar to other Cretaceous coals in the Rocky Mountain region; they are probably vitrinite-rich coal beds. Ash content ranges from 1 to 28 percent. Gas content ranges from less than 1 to more than 540 Scf/t and averages 147 Scf/t. Thermal maturity of Williams Fork coal beds ranges from 0.4 to 0.7 percent R_o. At this level of thermal maturity, the gases generated from the coal beds might be expected to be both thermogenic and biogenic. Gases desorbed from coal are dry with a gas dryness index (the ratio of methane to methane through pentane-$C_1/C_{1\text{-}5}$) ranging from 0.79 to 1.0. Carbon dioxide content ranges from 1 to 25 percent. Coal beds in the Williams Fork attained their level of thermal maturity during Oligocene time, during maximum burial.

The play area is lightly to moderately explored. About 5 wells have tested the production potential of Williams Fork coal beds. To date, there is no commercial production. Potentially good areas for reserves may occur along the crests of folds where gas can accumulate by buoyancy or in areas where the flow of water in the coals is impeded by a permeability discontinuity, such as a fault. Other potentially good areas for gas production include areas where the water table has been lowered, such as wells located in close proximity to surface mining. In these areas, gas begins to desorb from the coal matrix because of the reduction in pressure caused by the dewatering process; gas then flows to the well bore along the cleat system.

3753. GREATER GREEN RIVER BASIN–ALMOND PLAY

The Greater Green River Basin–Almond Play encompasses an area of about 2,200 sq mi and occurs in two, widely separated areas. The first area is located in the southeast part of the Washakie Basin and the southeastern part of the Sand Wash Basin. The second area is located around the flanks of the Rock Spring Uplift, and extends southward into Colorado, on the west side of the Sand Wash Basin. The Almond coal zone contains 1 to 5 coal beds that range in thickness from 2 to 12 ft . Cumulative thickness of coal in the zone ranges from 15 to 37 ft. The coal beds were deposited in back-barrier depositional environments.

Almond coals are composed primarily of vitrinite macerals, but a large amount of the vitrinite is of a high-hydrogen type, and therefore the coals are both gas and liquid prone. On the basis of a few analyses of Almond coals, the ash content ranges from 3 to 15 percent. Thermal maturity ranges from 0.4 to 0.7 percent R_o and gas content is less than 100 Scf/t.

The Greater Green River Basin–Almond Play is immaturely explored. The few wells that have been drilled and evaluated in the Sand Wash Basin have encountered large amounts of water. Attempts to dewater the coals have been unsuccessful. Like the other coalbed methane plays in the Southwestern Wyoming Province (037), potentially good areas for reserves are those areas where the coals can be effectively dewatered.

3754. GREATER GREEN RIVER BASIN–LANCE PLAY

Like the Greater Green River Basin–Almond Play (3753), the Greater Green River Basin–Lance Play has two play areas. The first is located on the east side of the Washakie Basin and extends southward into Colorado into the southeast part of the Sand Wash Basin. The second area is located around the Rock Springs Uplift, extending southward into Colorado on the west side of the Sand Wash Basin. The combined areas encompass about 2,700 sq mi. The more laterally persistent coal zone occurs in the lower part of the Lance Formation. Stray coals occur mainly in the middle part of the Lance. The main coal zone ranges in thickness from 100 to 400 ft. There are 1 to 8 coal beds in the Lance that have a cumulative thickness of as much as 85 ft. Individual coal beds are as thick as 13 ft. Coal beds in the Lance Formation were deposited in fluvial dominated systems.

Thermal maturity of coal beds in the Greater Green River Basin–Lance Play ranges from 0.4 to 0.65 percent R_o. Organic thermal maturation was achieved in Oligocene time, during maximum burial. The coals are inferred to be vitrinite-rich with ash contents of 3-20 percent. Gas content of these coals is unknown, but they are assumed to be comparable to coals of similar rank and quality elsewhere. The level of thermal maturity of Lance coal beds indicates that the sorbed gas may be a mixture of thermogenic and biogenic gas.

The Greater Green River Basin–Lance Play is immaturely explored, and coalbed methane potential has not been tested. The low levels of thermal maturity are indicative of low levels of gas content. The low gas content in conjunction with probable high water content, indicate the necessity of locating wells in areas that are at or slightly above the regional water table, such as along the crests of folds, lenticular coals that are not exposed to water recharge areas, or areas where faults have impeded the flow of water.

3755. GREATER GREEN RIVER BASIN–FORT UNION PLAY

The Greater Green River Basin–Fort Union Play encompasses an area of about 6,500 sq mi and occurs in two areas. The first is in the Moxa Arch-LaBarge Platform area in the western part of the Southwestern Wyoming Province (037). The second area covers nearly all of the eastern part of the Province, exclusive of the deeper parts of the Great Divide, Washakie, and Sand Wash Basins. Coal occurs in several parts of the Fort Union. However, the most important and laterally persistent coal zone is in the lower part of the Fort Union Formation. The coal zone ranges in thickness from 150 to 350 ft and contains from 1 to 9 coal beds. The cumulative thickness of coals within the zone ranges from 10 to 100 ft. Individual coal beds are as thick as 50 ft. Coal beds in the Fort Union were deposited in fluvial environments.

The level of thermal maturity ranges from 0.4 to 0.65 percent R_o. The coals are inferred to be vitrinite-rich with ash contents ranging from 1 to 25 percent. Gas contents from Fort Union coals in the Sand Wash Basin range from 9 to 301 Scf/t and more commonly are less than 100 Scf/t. Adsorption isotherms of Fort Union coals in the Sand Wash Basin indicate that the gas storage capacity is generally less than 300 to 400 Scf/t. These data indicate that Fort Union coals may be regionally undersaturated and will require significant reductions of pressure in order to initiate gas flow. On the basis of the low level of thermal maturity, coal-derived gas is probably a mixture of thermogenic and biogenic gas.

The Greater Green River Basin–Fort Union Play is immaturely explored. Excessive water production is the main obstacle to economic gas production. The low levels of gas contained in the coal in conjunction with high levels of water saturation require areas where dewatering can be achieved. Areas where the water table has been drawn down, such as near active surface mines, may be potentially good sites for coalbed methane wells. Other areas of some potential include areas where the flow of water through coal has been impeded or along the crests of folds where gas can accumulate by buoyancy.

RATON BASIN PROVINCE (041)

By Dudley D. Rice and Thomas M. Finn

Three coalbed gas plays are identified in the Raton Basin Province (041). They are the Northern Raton Basin Play (4150), the Raton Basin–Purgatoire River Play (4151), and the Southern Raton Basin Play (4152).

Tyler and others (1991), Stevens and others (1992), and Close and Dutcher (1993) have described the geologic controls and potential of coalbed gas in the Raton Basin, southeastern Colorado and northeastern New Mexico.

In the Raton Basin, coal beds with potential for coalbed gas are contained within the Upper Cretaceous Vermejo and Upper Cretaceous-Paleocene Raton Formations. The Vermejo Formation is as much as 350 ft thick and individual coal seams are as much as 14 ft thick. The cumulative coal thickness for the formation ranges from 5 to 35 ft. The overlying Raton Formation is as much as 1,600 ft thick and has a net coal thickness in the range from 10 to 120 ft. Although the Raton Formation contains more coal, individual coal seams are thinner, more discontinuous, and distributed over 1,200 ft of section. The nature of the coal seams in the two formations is controlled by depositional environment; the Vermejo was deposited in a lagoonal environment; whereas, the Raton was deposited in a fluvial setting. Although coal beds are as much as 4,100 ft deep in the northern part of the basin along the LaVeta Syncline, they are generally less than 1,200 ft over a large part of the basin.

The rank of coals in the Vermejo Formation ranges from high-volatile C bituminous along the margins of the basin to low-volatile bituminous in the central part of the basin. The rank generally coincides with present-day depth of burial and structural configuration, and probably resulted from maximum depth of burial that occurred in early Tertiary time. However, the highest ranks (low-volatile bituminous) occur along the eastward-flowing Purgatoire River where the present-day depths of burial are less than about 1,200 ft. These high ranks are interpreted to be the result of high heat flow from the crust, upper mantle, and (or) deep igneous intrusions which was transferred laterally by groundwater flow in middle Tertiary time. During this time, Vermejo and Raton coal beds commonly served as planes of weakness for igneous intrusions. However, the thermal maturity of the coal beds is only locally affected (one-dike width) by the intrusions.

Coalbed gases from production tests in the Raton Basin are composed mostly of methane with minor amounts of ethane, carbon dioxide, and nitrogen (each less than 1 percent). Isotopic analyses indicate that the gases are predominantly of thermogenic origin and were probably generated during time of maximum burial and (or) heat flow. Some mixing of relatively recent biogenic gas may occur in areas of groundwater flow.

The Raton Basin is a strongly asymmetric basin with a gently dipping eastern flank and a steeply dipping western flank that is thrust-faulted. Several major folds are located along the western margin of the basin. Minor normal faulting occurs within the basin with displacements generally less than 50 ft. The primary fracture permeability system in both the coals and adjoining rocks is oriented east-west.

Regional groundwater flow in the basin is eastward. Recharge is along the elevated, western outcrops which are characterized by higher rainfall. Discharge is at outcrops along the lower eastern margin and also along the Purgatoire River Valley. Reservoir pressures for coal beds are generally underpressured in relation to hydrostatic pressure (less than 0.43 psi/ft). TDS concentrations are relatively low (less than 5,000 ppm) for coalbed waters, indicating a short residence time and continuous recharge from adjacent sandstones, dikes, sills, and (or) the coals themselves. Because of the low TDS contents, produced coalbed waters might be utilized for irrigation or stock, which would keep development costs lower.

Gas contents of coal beds in the basin are highly variable and range from 4 to 810 Scf/t. These contents seem to correlate more closely with depth below the hydrologic potentiometric surface than with depth below the ground surface. On the basis of coal thickness, coal density, drillable area, and gas content, in-place coalbed gas resources of the Raton Basin are estimated to be as much as 12 TCF.

Some coal is produced by both underground and surface methods in the Colorado and New Mexico parts of the basin. Mine-related emissions are minor. A recent explosion in an underground mine near Trinidad, Colorado, indicates that the coal beds are gassy.

Since the late 1970's, more than 110 exploration wells have been drilled for coalbed gas in the Raton Basin, both in Colorado and New Mexico. Production tests have been variable, but gas rates more than 300 MCF/D have been reported. At present, all wells are shut-in because of the absence of gas pipelines in the basin. However, a pipeline is currently under construction and a pilot nitrogen injection project for coalbed gas wells has been approved.

4150. NORTHERN RATON BASIN PLAY,

4151. RATON BASIN–PURGATOIRE RIVER PLAY,

4152. SOUTHERN RATON BASIN PLAY

The target area for coalbed gas is where coal beds of the Vermejo and Raton Formations are greater than 500 ft deep. The thicker, more continuous seams of the Vermejo Formation are probably better targets for coalbed gas production. The target area is divided into 3 plays based on depth, coal rank, and concentration of gas in place: Northern Raton Basin Play (4150), Raton Basin–Purgatoire River Play (4151), and Southern Raton Basin Play (4152). Exploration wells have been drilled for coalbed gas in all three plays, but, as stated before, production has not been established. The reserve potential of coalbed gas from all three plays is considered to be very good, but production will depend on infrastructure development, particularly pipeline construction.

In the Northern Raton Basin Play (4150), coal rank is as much as medium-volatile bituminous and depths of burial are as much as 4,100 ft, the deepest in the basin. Because of the increased depths, there is a large amount of gas in-place (as much as 24 BCF/sq mi). The potential for reserves in this play is considered to be good, with low permeability resulting from burial depth a possible negative factor.

The Raton Basin–Purgatoire River Play (4151) occurs in the central part of basin where coal ranks (medium- to low-volatile bituminous) and gas contents (more than 300 Scf/t) are high, and drilling depths are relatively shallow (less than 1,200 ft). These factors result in a good potential for reserves of coalbed gas from this play.

In the Southern Raton Basin Play (4152), coal ranks are as much as medium-volatile bituminous, but depths of burial are less than 1,400 ft. Because of these relatively shallow depths, concentrations of gas in-place are about 8 BCF/sq mi or less. The reserve potential of this play is also regarded as good.

REGION 7–MIDCONTINENT

By Dudley D. Rice, Thomas M. Finn, and Joseph R. Hatch

In the Midcontinent Region, abundant coal resources are located in the Cherokee Platform, Forest City Basin, and Northeast Oklahoma Shelf, which are part of the Western Interior Coal Region, and the Arkoma Basin. The coals of Pennsylvanian age were once major targets for mining, particularly underground mining. Now relatively small amounts of coal are produced mainly by surface mining. In-place coalbed gas resources have been estimated for the Arkoma Basin; they represent less than 1 percent of the U.S. total. Potential reserves of coalbed gas are assessed for the Arkoma and Forest City Basins and the Cherokee Platform.

FOREST CITY BASIN PROVINCE (056)

One hypothetical play, the Forest City Basin–Central Basin Play (5650) is identified in the Forest City Basin Province (056).

The coalbed gas potential of the Forest City Basin of Iowa, Kansas, Missouri, and Nebraska is described by Tedesco (1992) and Bostic and others (1993a, b). Deep coal resources of Kansas are assessed by Brady (1990). In general, information to fully evaluate potential coalbed gas reserves in the basin is limited.

In the Forest City Basin, coal-bearing strata are present in the Pennsylvanian Atokan and Desmoinesian Series. In all four States, the coals are assigned to the Riverton Formation and the Cherokee, Marmaton, and Pleasanton Groups. The coal-bearing units are cyclothems made up of shale, sandstone, limestone, and coal. More than 40 individual beds have been identified, and many have been mined for more than 100 years, both underground and on the surface. Some of the important coal beds, in ascending order, which correlate across State boundaries, are Riverton, Weir-Pittsburg, Mineral, Scammon, Fleming, Tebo, Croweburg, Bevier, Summit, Mulky, Mystic, and Mulberry. The coal beds are relatively widespread and commonly too deep to mine. As a result, many parts of the basin are underlain by multiple, unmined coal beds. Drill holes indicate that the cumulative coal thickness may be as much as 22 ft, and individual beds may be as thick as 10 ft. However, many of the beds are less than 2 ft thick, and multiple-seam completions may be required for commercial production. The coal-bearing section is as much as 1,600 ft deep along the axis of the basin in southwestern Iowa.

The rank of Pennsylvanian coals ranges from high-volatile C to A bituminous. Rank increases with depth and apparently to the west where greater depths of burial exist. In addition, higher heat flow in the west might have been associated with structural movements along the Nemaha Uplift. Maximum burial occurred in late Paleozoic or early Mesozoic time. The coal ranks are marginal with respect to significant thermogenic hydrocarbon generation.

Desorbed gas samples consist mostly of methane (72 to 93 percent). Other significant components are ethane and CO_2. The isotopic composition of the gases indicates that at least some of the gas, which was probably formed relatively recently in association with groundwater flow, may be of biogenic origin. The high amounts of ethane are probably the result of fractionation during the desorption process.

The Forest City is a structural basin of Pennsylvanian age and, based on existing data, appears to be relatively undeformed. A series of northwest-southeast trending folds and faults has been documented in Missouri. In addition, recurrent movement has taken place on the Nemaha Uplift, which forms the western border, and the Thurman-Redfield Structural Zone in Iowa, which might have locally enhanced permeability.

Gas content information is limited in the Forest City Basin. Measurements from one well in Kansas ranged from 21 to 94 Scf/t over the depth interval of 757–1158 ft. These values are relatively low, and more measurements are needed to properly evaluate the coalbed gas potential. Excessive amounts of methane and associated explosions were reported in underground mines of Missouri from 1881 to 1905. Coalbed gas resources have not been estimated for the basin.

Large amounts of coal were produced along the eastern and northern flanks of the basin in the past, particularly during World Wars I and II. At present, limited surface mining is being done in Iowa, Kansas, and Nebraska.

Since 1990, more than 10 wells have been drilled for coalbed gas in the Kansas and Missouri parts of the basin. Data are not available from these wells, and production has not been established. In addition, some other wells may have coalbed gas commingled with gas produced from other zones in the Cherokee Group. The northeastern part of the basin, particularly in Kansas, is underlain by shallow, low-pressure oil and gas fields. As a result, some infrastructure is in place for the development of coalbed gas, both from new wells and recompletions in old wells.

5650. FOREST CITY BASIN–CENTRAL BASIN PLAY (HYPOTHETICAL)

On the basis of limited data, one hypothetical coalbed gas play is recognized in the Forest City Basin, the Forest City Basin–Central Basin Play (5650). The play terminates at the Nemaha Uplift on the west and the Bourbon Arch on the south. On the east and north flanks of the basin, the play outline is defined by the 300 ft depth of burial for the coal-bearing strata. The potential for reserves of coalbed gas in this play is graded as fair to poor, with low rank associated with low gas contents as the main limiting factors.

CHEROKEE PLATFORM PROVINCE (060)

One play, the Cherokee Platform–Central Basin Play (6050), is identified in this province.

Stoeckinger (1989, 1990) has evaluated the coalbed gas potential of the Cherokee Platform, southeast Kansas. Barker and others (1992) provided new information on thermal maturity patterns that will affect coalbed gas potential. The geologic framework and many of the characteristics pertaining to coalbed gas are the same for both the Cherokee Platform and Forest City Basins. The big difference is that economic development of coalbed gas has taken place in the Cherokee Platform, making more data available for assessing the recoverable coalbed gas potential.

The thickest coal seams in the Cherokee Platform are assigned to the Middle Pennsylvanian (Desmoinesian) Cherokee Group, which varies in thickness from 300 to 500 ft. The Cherokee Group consists mostly of black shales, with lesser amounts of limestone, sandstone, and coal. The main coalbeds in the basin, is ascending order, are Riverton, Rowe, Weir-Pittsburg, Mineral, Fleming, Croweburg, Bevier, and Mulky. The Riverton, Weir-Pittsburg, Bevier, and Mulky are the thickest, and the Weir-Pittsburg seam can be as much as 5 ft thick. Net thickness of the coals in the Cherokee Group, based on geophysical logs, is greater than 15 ft. Depths of burial for the target coal beds are in the range of 600–1,200 ft.

The Pennsylvanian coals in the Cherokee Platform are generally high-volatile B to A bituminous in rank, and this coalification pattern is related to maximum burial in Permian time. However, "hot spots" exist where rank of the coal beds may be as high as medium-volatile bituminous. These "hot spots", which are restricted to the southeast part of the basin, are interpreted to be the result of warm waters, which originated from southerly basins during late Paleozoic time. These warm waters flowed upward from permeable Mississippian rocks along fractures and (or) faults into locally permeable Pennsylvanian rocks. These localized areas of higher rank resulted in conditions favorable for the significant generation of thermogenic hydrocarbons during late Paleozoic time.

Methane makes up more than 97 percent of the hydrocarbon fraction of the produced coalbed gases in the Cherokee Platform. Minor amounts of CO_2 (average 1.1 percent) and nitrogen (average 1.6 percent) are also produced with the methane. Although isotopic values are not available, the gases were probably generated by thermogenic processes in late Paleozoic time. In addition, minor amounts of waxy oil, which are the result of thermogenic processes, are also produced.

The Cherokee Platform is generally characterized by beds gently dipping to the west. However, there are local folds and normal faults with small relief that have distinct northeast-southwest and northwest-southeast orientations. These structures appear to be basement-controlled, and some experienced recurrent movement during deposition. Relief on these structures increases with depth. In addition, differential compaction of thick shales that underlie most coal beds also influenced the orientation and intensity of cleating in the coal.

As much as 20 barrels of saline water (TDS as much as 90,000 ppm) are produced from typical coalbed gas wells per day. The high salinity and low quantity of water suggest that there is not active groundwater flow. The water is injected into the Ordovician Arbuckle carbonates, which are only 400 ft below the Pennsylvanian coals.

Gas contents as high as 240 Scf/t have been reported from the deeper Weir-Pittsburg coal seams, and a strong relation exists between gas content and depth. Although data are not available, a probable relation also exists between higher gas contents and the "hot spots". On the basis of an average coal thickness of 6 ft and a gas content of 200 Scf/t, in-place gas resources of 1.3 BCF/ sq mi have been estimated for the area.

Southeast Kansas, where part of the Cherokee Platform is located, has produced 99 percent of the coal mined in the State. Production has generally been declining since World War II and production from surface mining has exceeded that from underground mining since 1931. Future coal mining is limited by the thin coal seams and high sulfur content. However, these two factors do not limit the coalbed gas potential.

Following the depletion of oil and gas in conventional Pennsylvanian sandstone reservoirs, a type of unconventional gas, which was referred to as "shale gas," was developed in southeast Kansas in the 1920's. Although the presence of this type of gas was known earlier, accumulations were not commercial because of the low gas volumes and produced salty water. The Mulky coal bed, which is less than 2 ft thick and the shallowest coal seam in the Cherokee Group, is now considered to be the main source of this "shale gas". The shallow "shale gas" wells were characterized by slow decline, long life, low operating costs, and few dry holes. The wells were drilled by cable tool and all completions were open hole. Wells lasted 8 to 10 years with some initial flows as much as 100 MCFGPD. Wells in large areas (several hundred sq mi) had the same general characteristics; organic richness and fracturing were considered to be the key to commercial production. Structural position was considered to be important in establishing commercial production, and wells were placed on structural highs probably resulting in less water production and enhanced fracturing.

As a result of the tax credit, exploration has been ongoing since the late 1980's for coalbed gas in the Cherokee Platform with the activity concentrated around Montgomery County, Kansas. In 1992, more than 230 wells produced approximately 5 BCF of coalbed gas. Although many completions are newly drilled wells, older oil and gas wells have also been recompleted in nearby coal beds. In contrast to earlier "shale gas" development in the 1920's, one or more coal seams are stimulated in present-day wells.

Because of earlier development of shallow oil and gas in conventional Cherokee sandstone reservoirs, the infrastructure is generally in place for development of coalbed gas resources in southeast Kansas. The keys to the current development of the coalbed gas resource have been the low drilling, completion, and water-disposal costs and existing infrastructure.

6050. CHEROKEE PLATFORM–CENTRAL BASIN PLAY

One coalbed gas play, Cherokee Platform–Central Basin Play (6050), is identified in the Cherokee Platform. The play area is bounded on the west by the Nemaha Uplift, on the north by the Bourbon Arch, and on the south by the Chatauqua Arch. On the east side, the play limit is defined by the area where Pennsylvanian coal beds are less than 300 ft deep or have been surface mined. Localized "hot spots" have resulted in higher gas contents and have increased permeability in small-scale structural features. A good potential for additions to reserves of coalbed gas is estimated, especially in the "hot spots" where the gas contents are higher.

ARKOMA BASIN PROVINCE (062)

Two plays have been identified in the Arkoma Basin Province (062). They are the Arkoma Basin–Anticline Play (6250) and the Arkoma Basin–Syncline Play (6251), which is hypothetical.

Geologic controls and coalbed gas potential of the Arkoma Basin of east-central Oklahoma and west-central Arkansas are given by Friedman (1982), Rieke and Kirr (1984), Diamond and others (1988), and Houseknecht and others (1992).

The economic coal deposits of the Arkoma Basin are of Middle Pennsylvanian (Desmoinesian) age and are assigned to the Hartshorne (Sandstone), McAlester, Savanna, and Boggy Formations. Although more than 20 individual coal seams have been identified, the target coal beds for gas in Oklahoma, in ascending order, are the Hartshorne, McAlester/Stigler, Cavanal, Lower Witteville, and Secor. In Arkansas, the target coal beds for gas, in ascending order, are the Hartshorne, Charleston, and Paris. The Hartshorne Coal Zone, which forms the base of the coal-bearing interval, is economically important because of its thickness and continuity, and in the southern part of the basin splits into 2 beds (Lower and Upper). These 2 Hartshorne seams are separated by shale and sandstone, which are as much as 100 ft thick. Individual coal beds are as much as 10 ft thick in the basin, are relatively continuous, but are variable in thickness. The Hartshorne coal bed crops out on folds and faults within the basin and extends to depths of more than 7,000 ft. Most coal resources for the Hartshorne interval occur in the depth range of 500–1,500 ft.

Coal ranks increase significantly eastward from high-volatile C bituminous to semianthracite. The coals of semianthracite rank are in the Arkansas part of the basin and represent the highest ranks for an area that is considered to have potential for additions to reserves of coalbed gas. The lateral changes in thermal maturity within the Pennsylvanian and the overall high rank are difficult to explain by burial depth. The high rank is interpreted to be the result of hydrothermal fluids that originated in the Ouachita Orogenic Belt to the south. These hot fluids moved along syndepositional faults that were active during Atokan time. The postulated eastward fluid flow in the Desmoinesian coal-bearing rocks was controlled by sandier facies. Thermogenic hydrocarbons were probably generated in the Pennsylvanian coal beds during Late Paleozoic at the time of high heat flow.

Gases from horizontal degasification wells and desorbed core from the Hartshorne coalbed are composed mostly of methane with minor amounts of CO_2 (less than 1.6 percent) and heavier hydrocarbon gases (generally less than 1 percent). On the basis of isotopic analyses, the gases are interpreted to be mainly of thermogenic origin, although probable mixing of biogenic gas, generated relatively recently in association with groundwater flow, has occurred.

The Arkoma Basin is a foreland basin bounded by the Ouachita Orogenic Belt to the south. The main structural features of the basin that affect coalbed gas potential are a series of northeast- to east-trending synclines and tightly folded, faulted anticlines. The coal-bearing Pennsylvanian rocks are eroded in many of the anticlines and dips range from a few degrees in the synclines to nearly vertical on the anticlines. The synclinal folds form mountains with several hundred feet of relief. Anticlines occupy about 35 percent of the basin area, whereas the synclines occupy approximately 65 percent. Normal faults with large displacements, which are probably rooted in the basement, parallel the axes of the anticlines. The intensity of the structural deformation, both folding and faulting, decreases in a northward direction away from the Ouachita Orogenic Belt.

The orientation of face cleats ranges from N. 32¡ W. to N. 17¡W., which is essentially perpendicular to the folds and faults in the basin. In addition, inclined fractures dip at angles from 45¡ to 55¡ within the coal beds. These fractures are probably related to shear, and are probably concentrated in the tightly folded anticlines. The coals, as observed in the Hartshorne coal bed, are friable due to the abundant shear fractures, which are superimposed on a closely spaced cleat system. The effect of this friability on permeability is not well-known.

Information is limited on the hydrogeology of coal beds in the Arkoma Basin. Coalbed gas wells completed on structural highs are relatively dry; however, those completed in structural lows may produce as much as 50 or more barrels of water per day.

As confirmed by mine emissions data, coal beds in the Arkoma Basin are very gassy and have been a serious hazard for underground mining in the past. Desorbed gas contents range from 200 to 675 Scf/t and are related to present-day depth. However, gas contents have only been measured to depths of about 1,500 ft, and higher values are expected at greater depths. On the basis of a minimum gas content of 200 Scf/t and a maximum value of 450 Scf/t, the in-place coalbed gas resources of the Arkoma Basin are estimated to range from 1.6 to 3.6 TCF.

Coals have not been produced from the steeply dipping coal beds of the Oklahoma part of the Arkoma Basin since 1984 because of high costs. As a result, emissions from underground coal mines have been minimal. In Arkansas, some surface mining is still taking place.

Starting about 1930, coalbed gas was produced for 10 to 15 years from shallow wells (less than 500 ft) in the Kinta area, Oklahoma. The wells were drilled by cable tool and the gas was used locally. In addition, gas has been produced recently from sandstone reservoirs in the Hartshorne Sandstone in three small gas fields. Studies on gas geochemistry have shown that most of the gas in the sandstone reservoirs was probably generated in the adjacent coal beds. Since 1989, as many as 100 coalbed gas wells have been drilled, mainly to the Hartshorne coal bed. The only production to date is from the Kinta area where 40 wells at relatively shallow depths (600 to 800 ft) produce an average of 50 MCFPD. These wells were drilled on the flank of an anticline; no water is produced.

An infrastructure of roads, pipelines, and field services is in place because of earlier deeper, high pressure, conventional gas development. However, compression of coalbed gas will probably be required before the existing pipelines can be used. Shallow wells on the anticlines will have low drilling and operating costs. Deeper wells in the synclines will probably have water production and disposal of that water will increase the costs of development.

Target areas for coalbed gas in the Arkoma Basin are areas where coal beds are generally deeper than 500 ft deep and where the Hartshorne coal bed has not been mined out along steeply dipping flanks of anticlines. The basin is favorable for in-place coalbed gas resources because of the abundant coal resources and high gas contents, but potential additions to reserves are questionable, especially in the eastern part of the basin where the structurally deformed coal beds are of high rank. Commercial production of coalbed gas has not been established from coals of semianthracite rank in the United States.

6250. ARKOMA BASIN–ANTICLINE PLAY
6251. ARKOMA BASIN–SYNCLINE PLAY (HYPOTHETICAL)

Similar to the Northern Appalachian Basin, the Arkoma Basin has two coalbed gas plays based on structure: Arkoma Basin–Anticline Play (6250) and Arkoma Basin–Syncline Play (6251).

The Arkoma Basin–Anticline Play (6250) is located on the crests and shallow flanks of tightly folded anticlines. Gas contents will be generally lower because of the shallower depths and partial degassing. Permeability may be higher because of tectonic enhancement, but the effects of abundant, inclined fractures on permeability and flow rates have not been fully evaluated. All the coalbed gas production to date in the basin comes from this play; no water is produced. The potential for reserves of coalbed gas in this play is considered to be good. A limiting factor is the lack of knowledge of reservoir properties of high-rank coal in structurally deformed areas.

The hypothetical Arkoma Basin–Syncline Play (6251) is located in regionally extensive, broad synclines, covers a large part of the basin, and occurs below the gas-water contact. The gas contents in this play will be higher than in the anticline play because of depth; however the gas production will probably be accompanied by water production. In addition, the permeability is questionable because of the greater depths. Although some wells have been drilled, no long-term production has been established, and therefore the play is hypothetical. The undiscovered potential of this play is rated as good, although information is generally lacking on the permeability of deeply buried, high rank coal.

REGION 8–EASTERN INTERIOR

The Eastern region is estimated to contain 16 percent of the in-place coalbed gas resources of the lower 48 States in coal beds of Pennsylvanian age. Within this region, potential additions to reserves have been estimated for plays in the Appalachian Basin Province (067), Black Warrior Basin Province (065), and Illinois Basin Province (064). On the basis of 1991 tonnage, this region contains the top five underground coal mining States in the country. They are, in descending order of production, West Virginia, Kentucky, Illinois, Pennsylvania, and Virginia. As of 1988, the States with the largest volume of methane emissions from underground mines were, in descending order, West Virginia, Alabama, Virginia, Pennsylvania, and Illinois. Once again, these States are all located in the Eastern Interior region. Although the in-place coalbed gas resources are small, the region is important for development because of (1) emissions related to underground coal mining, and (2) proximity to large populations centers. To date, the question of gas ownership has been an obstacle to development in many parts of the region.

ILLINOIS BASIN PROVINCE (064)

By Dudley D. Rice, Thomas M. Finn, and Joseph R. Hatch

One coalbed methane play is identified in the Illinois Basin, the Illinois Basin–Central Basin Play (6450).

The geologic aspects of the coalbed gas potential of the Illinois Basin are summarized by Archer and Kirr (1984). Thermal maturity trends and controls in the basin are discussed by Cluff and Byrnes (1991). Harper (1991) described the coalbed gas potential of abandoned underground mines in Indiana. Abandoned mines also have potential for coalbed gas production in Illinois and Kentucky.

Middle Pennsylvanian (Desmoinesian) coal seams are important for coal mining in the Illinois Basin, both surface and underground, and have potential reserves of coalbed gas. Coal beds also occur in the Lower and Upper Pennsylvanian section, but they are generally thin and discontinuous. In Illinois, the coals are generally referred to by geographic names; however, in Kentucky and Indiana they are commonly referred to by number with the oldest coal having the lowest number. More than 75 seams have been identified in the basin and about 20 have been mined. The major seams for both mining and coalbed gas potential, in ascending order, are Colchester No. 2, Houchin Creek No. 4, Springfield No. 5, Herrin No. 6, and Danville No. 7. Coal seams are variable in thickness and continuity and can be as much as 15 ft thick. More than one half of the minable coal (more than 28 in thick) occurs in beds less than 54 in thick. The thinner coals, which are not important for mining, are important for coalbed gas potential because multiple-seam production may be needed for economic development. The greatest net thickness of coal probably occurs in the southeastern part of the basin where the Pennsylvanian section is thickest. In the Illinois part of the basin, one half of the coal resources are at depths less than 650 ft deep. Over the entire basin, all coal seams are less than 3,000 ft deep, and the thick Middle Pennsylvanian coals are less than 1,500 ft deep.

Coal rank in the basin increases to the southeast from high-volatile C to A bituminous rank. Isorank trends commonly cut across structure in the southern part of the basin, and coals of highest rank commonly crop out. The observed coalification pattern can be explained in two ways. First, maximum depth of burial occurred in late Pennsylvanian or Permian time, and as much as 5,000 ft of uplift and erosion has occurred since that time. The second explanation is that short-term elevation of the geothermal gradient, related to deep-seated igneous intrusions, occurred in the Hicks Dome area of the southern part of the basin during late Pennsylvanian to Triassic time. The southerly increase in rank can best be explained by a combination of both factors. Because of the generally low rank, probably only minor amounts of thermogenic gas were generated in the Pennsylvanian coals in late Paleozoic and early Mesozoic time.

Gas samples desorbed from cores and sampled from abandoned mines consist mainly of methane (as much as 90 percent), nitrogen (as much as 58 percent), and CO_2 (as much as 21 percent). The high nitrogen values are interpreted to result, in part, from air contamination. The amount of nitrogen in gases produced from abandoned mines usually decreases with time, indicating air contamination. The carbon isotopic composition of the methane fraction of the coalbed gas samples suggests a biogenic origin, and the gases were probably formed relatively recently in association with groundwater flow.

The Illinois Basin is a broad, relatively undeformed structural depression. In addition to several north-south trending folds, the main structural features of the basin are high-angle faults concentrated in the south part of the basin. These faults, such as those in the Rough Creek-Shawneetown Fault Zone, exhibit significant displacement and lateral extent and trend approximately east-west. In addition, numerous small-scale north-south trending thrust faults with displacements up to 10 ft have been observed only in coal mines. These thrust faults are related to the contemporary stress field in the region.

Systematic studies have not been made of the cleat systems in the basin. In general, cleats are not readily apparent in small-scale studies, and the fractures in the coal have a tendency to be mineralized. However, the density of fracturing is expected to be higher in the southern part of the basin where faulting and folding are concentrated.

Relatively small amounts of water are pumped from most underground mines, suggesting that the coals have low permeability. Many mines, even those below surface drainage, remain dry after abandonment if the roof and floor rocks are relatively impermeable. Analyses of a few samples indicate that the water is relatively fresh.

Gas contents of coals in the Illinois Basin are low, ranging from about 30 to 150 Scf/t without any strong correlation with depth. In fact, some of the highest values are from relatively shallow horizons. The low gas contents can be explained by (1) relatively shallow depths, (2) low coal rank, (3) probable degassing of any thermogenic gas generated earlier, and (4) replacement by lower concentrations of relatively recent biogenic gas. In spite of these relatively low gas contents, Illinois had the fifth largest methane emissions from underground mining in 1988; this gas could be targeted for possible recovery and utilization.

On the basis of coal resource estimates and a range of gas content values, the in-place coalbed gas resources for the Springfield No. 5, Herrin No. 6, and Danville No. 7 coal beds are estimated to range from about 5 to 21 TCF. Significant coal resources occur in other beds that are commonly thinner, but deeper with probable higher gas contents. The addition of potential gas resources for these other coal beds would add to these in-place estimates.

Illinois, which contains a large part of the Illinois Basin, is an important state for coal resources, mining, and emissions. Of all the States, it has the largest bituminous coal reserves, largest strippable bituminous coal reserves, and second largest coal reserves in the United States. On the basis of 1991 statistics, Illinois ranked fifth in the country for total coal production and third for coal production from underground mines. More than 70 percent of their coal was produced from underground mines. Several counties in both Illinois and Kentucky are in the top 35 counties in the U.S. in terms of underground mining. At present, very little underground mining is taking place in Indiana.

Only about 25 wells have been drilled for coalbed gas in the Illinois Basin. Most of these wells were drilled to recover gas from abandoned mines less than 500 ft deep, which were mined by the room-and-pillar method. The gas in these mines probably migrates not only from the coal, but also from adjacent roof and floor rocks. One well in an abandoned mine had stabilized flow rates of about 100 MCFGPD for about 20 years. With the recent tax credit, some effort has been made to recover gas from virgin coal beds, but no information is available.

The gas in abandoned mines has also created a hazard for drillers who are exploring for oil and gas from deeper reservoirs in the mining districts. During the past 20 years, many drilling rigs have been destroyed by fire after penetrating gas-filled, abandoned mine workings.

Mostly oil is produced from conventional reservoirs in the Illinois Basin. In addition to the oil pipelines, a couple of regional, high-pressure gas pipelines are present in the potential area for coalbed gas. However, more infrastructure is required for future development of coalbed gas.

6450. ILLINOIS BASIN–CENTRAL BASIN PLAY

The Illinois Basin–Central Basin Play (6450) is the one coalbed gas play identified in the Illinois Basin. It corresponds to the area where the Herrin No. 6 coal bed is generally deeper than 200 ft and is covered by Upper Pennsylvanian (Missourian) rocks. Although the coal resources of the basin are large, potential reserves of coalbed gas are essentially untested and assessed to be fair to poor. The potential for reserves is restricted because of (1) low gas contents, (2) questionably low permeability, and (3) possible undersaturation. The best potential is in the southern part of the basin where the coal beds are of higher rank and deeper. This is the part of the basin where most of the wells have been drilled.

The coalbed gas resource can be developed by two types of wells. First, wells may be drilled into shallow, abandoned underground mines where the gas is migrating from both the coal beds and adjoining rocks. These wells will undoubtedly be characterized by low pressure and the gas will be contaminated by air (nitrogen) during early stages of production. Gas from these wells might be used for local consumption. Second, vertical, hydraulically-fractured wells may be drilled into virgin coal seams. Maximum production will be gained by completion in multiple coal seams.

BLACK WARRIOR BASIN PROVINCE (065)

By Dudley D. Rice and Thomas M. Finn

Four coalbed gas plays are identified in the Black Warrior Basin Province (065). These are the Black Warrior Basin Recharge Play (6550), the Black Warrior Basin–Southeastern Basin Play (6551), the Black Warrior Basin–Coastal Plain Play (6552), and the Black Warrior Basin–Central and Western Basin Play (6553).

The Black Warrior Basin is located in Alabama and Mississippi. McFall and others (1986a) and Pashin (1991) described the controls and potential for coalbed gas in the Alabama portion of the Black Warrior Basin where all of the development has taken place. Details of geologic and engineering controls on coalbed gas production in the Cedar Cove area are given by Ellard and others (1992) and Sparks and others (1993). The Gas Research Institute conducted a multi-year research program at the Rock Creek Site within the Oak Grove field. Reservoir characterization of coal beds in the Rock Creek Site is provided by Young and Paul (1993) and in issues of the Gas Research Institute's Quarterly Review of Methane from Coal Seams Technology from 1983. Henderson and Gazzier (1989) and Ericksen (1992) provide some information on the coalbed gas potential of the Mississippi portion of the basin. The effects of surface discharge of produced waters from coalbed gas wells are reported by O'Neil and others (1993) and Shepard and others (1993).

The upper part of the Lower Pennsylvanian Pottsville Formation contains economically important coal beds, which are assigned to several widespread coal groups. The coal groups form the upper part of regressive sequences that coarsen upward from marine mudstone to nonmarine sandstone and thicken to the southeast. The potential for coalbed gas occurs in five groups, in ascending order: Black Creek, Mary Lee, Pratt, Cobb, and Gwin. The Mary Lee Coal Group is the most important for underground mining.

Individual coal beds are generally thin (less than 3 ft) throughout the basin, although the Blue Creek Bed of the Mary Lee Group is locally more than 9 ft thick. The coal beds are most abundant and thickest in the southeastern part of the basin where fluvial-deltaic platforms favored peat accumulation. As many as 40 individual coal beds are present in this part of the basin, and the net coal thickness is as much as 32 ft. The coal-bearing section dips gently to the southwest and the Black Creek Coal Group is at depths greater than 4,000 ft in the southern part of the potential area. Unconformably overlying the Pottsville in the western two-thirds of the basin are Cretaceous and younger sediments of the Gulf Coastal Plain.

The highest coal ranks in the basin, low-volatile bituminous for the Mary Lee Group, occur in a "bull's-eye" pattern along the border of Tuscaloosa and Jefferson Counties, Alabama, in the southeast part of the basin. This area generally coincides with the area of abundant and thick coal beds, and the present-day depth of burial is less than 3,000 ft. The coal ranks decrease away from this area (southwest, northeast, and northwest) and are as low as high-volatile C bituminous rank in Mississippi. The higher ranks in the southeastern part of the basin are the result of a combination of maximum depth of burial and higher paleoheat flow. Maximum depth of burial probably occurred during late Paleozoic time, and as much as 8,000 ft of erosion has probably taken place since that time. In addition, higher paleoheat flows might have resulted from hydrothermal flow in fractured strata adjacent to the Appalachian Orogen.

The produced coalbed gases in the Black Warrior Basin consist mainly of methane with less than 1 percent heavier hydrocarbons and less than 1 percent CO_2. The gases are interpreted to be mainly thermogenic and were generated during the time of maximum burial and heat flow, the late Paleozoic. Following uplift and erosion, some of the original thermogenic gas probably degassed, particularly at shallower depths. Mixing of relatively recent biogenic gas, which was generated in association with active groundwater flow, occurred in the shallower coal beds near the Appalachian Orogen.

Folds and thrust faults are restricted to the southeastern part of the basin and strike northeast. Strata in the anticlines, such as the Blue Creek Anticline, are intensely fractured as compared with those in the rest of the basin. Normal faults, which are generally oriented to the northwest, are abundant in the Black Warrior Basin. These faults are related to extensional tectonics and form a series of linear to arcuate horst and graben blocks. Syndepositional movement on these faults and folds strongly affected sedimentation, coalification, hydrology, and productivity.

In addition to the major normal fault system, two distinct sets of cleats are developed in the Pottsville coals. One dominant set, which is oriented to the northeast, has been reported throughout the Alabama portion of the basin. Another set is developed locally in the vicinity of Blue Creek Anticline and Opossum Valley Thrust Fault and the face cleats strike to the northwest.

The Pottsville Formation is an unconfined aquifer, and the coal beds are the most permeable units in the eastern part of the basin. Recharge of the Pottsville is at outcrops along the Birmingham Anticlinorium (part of the Appalachian Orogen) and groundwater flow is toward the northwest. Discharge takes place along the Black Warrior River and its tributaries. Potentiometric lows exist in areas of underground coal mining and coalbed gas production. In general, TDS of the waters associated with the coal beds increase with depth and sometimes exceed 30,000 ppm. However, several northwest-trending plumes of fresh water, characterized by low TDS (<3,000 ppm), extend out into the basin adjacent to the Birmingham Anticlinorium. This fresh-water flow is controlled by northwest-oriented faults and fractures. Daily water production from individual wells can exceed 1,200 barrels per day in these areas of increased permeability. Gas production rates can also be higher. In the western two-thirds of the basin, coastal plain sediments unconformably overlie the Pottsville and intercept meteoric recharge.

In the Black Warrior Basin, water production and disposal is considered to be a coal-mining activity. Most of the produced water is discharged into the Black Warrior River and its tributaries. Monitoring studies have indicated that the discharge has not significantly affected the river's water quality or biologic communities.

Desorbed gas contents of the Pottsville coal beds are similar to those of the Central Appalachian Basin and generally increase with depth and rank. The gas contents range from about 125 to 680 Scf/t. The highest values occur in the southeastern part of the basin ("bull's eye" area) where high ranks occur at shallow depth creating a very favorable situation for in-place and recoverable coalbed gas resources.

Pressure gradients in the upper Pottsville Formation are generally at hydrostatic gradient (0.43 psi/ft). The exception is underground coal mining areas, such as the Oak Grove and Jim Walter mines, where pressures as low as 0.32 psi/ft are reported.

The in-place coalbed gas resources in the Alabama portion of the Black Warrior Basin are estimated to be about 20 TCF. This estimate is for the Black Creek, Mary Lee, Pratt, and Cobb Coal Groups and does not include the younger Gwin Group, which has commercial production. More than 70 percent of the in-place resource is estimated to be contained in the lower Black Creek and Mary Lee coal groups.

Alabama ranked 12th in the country in terms of coal production in 1991 with more than 60 percent of the total coming from underground mines. Tuscaloosa followed by Jefferson were the most active counties for underground mining. The major target for underground mining is coal beds in the Mary Lee Group; large mined-out areas occur in Walker, Jefferson, and Tuscaloosa Counties. In 1988, only West Virginia emitted more methane than Alabama in association with underground coal mining.

The first coalbed gas production in the Black Warrior Basin was associated with underground coal mines. Production began in Oak Grove degasification field in 1981 and in Brookwood degasification field in 1982. In these two areas, hydraulically fractured vertical wells, horizontal in-mine wells, and gob wells are used to capture coalbed gas in association with mining. Since this earlier mining-related activity, development has rapidly expanded away from the mining areas. However, the development is restricted to the southeast part of the basin where coal beds are thicker, more numerous, and of higher rank. In 1993, more than 2,900 wells produced about 104 BCF of coalbed gas in the Alabama portion of the basin. In 1992, 91 BCF of coalbed gas was produced from about the same number of wells, which accounted for about 28 percent of the natural gas production in the State. In comparison, 36 BCF was produced in 1990 and 68 BCF in 1991. Production is from 16 degasification fields (Big Sandy, Blue Creek, Boone Creek, Brookwood, Cedar Cove, Deerlick Creek, Holt, Little Buck Creek, Little Sandy Creek, Moundville, Oak Grove, Peterson, Pleasant Grove, Robinson’s Bend, Taylor Creek, and Wolf Creek). In 1993, the most productive degasification fields, in descending order, were Blue Creek, Cedar Cove, Brookwood, Oak Grove, and Deerlick Creek. New drilling over the past 2 years has substantially decreased, and the emphasis has been on optimizing production with recompletions. According to the Gas Research Institute, the Black Warrior Basin had coalbed gas reserves of about 2,900 BCF at the end of 1993, which is second only to the San Juan Basin. Pipelines have been added in the basin to accommodate this increased production.

The area for potential additions to reserves of coalbed gas in the Black Warrior Basin, where the Pottsville coal beds are deeper than 500 ft, extends from northwestern Alabama to northeastern Mississippi. However, the highest potential is in the southeastern part of the basin in Alabama, the "bulls-eye," where the Pottsville coal beds are more abundant, thicker, of higher rank, and at relatively shallow depths. The properties related to coalbed gas potential in Mississippi are less well documented, but can be inferred from regional trends.

6550. BLACK WARRIOR BASIN RECHARGE PLAY,

6551. BLACK WARRIOR BASIN–SOUTHEASTERN BASIN PLAY,

6552. BLACK WARRIOR BASIN–COASTAL PLAIN PLAY,

6553. BLACK WARRIOR BASIN–CENTRAL AND WESTERN BASIN PLAY (HYPOTHETICAL)

Plays 6550, 6551, and 6552 occur where (1) the Black Creek Coal Group is deeper than 500 ft , (2) Mary Lee and older coal groups have rank equal to and greater than about high-volatile A bituminous, and (3) 15 or more coal beds are present in the Black Creek through Cobb interval. In addition, present production is restricted to these three plays.

The Black Warrior Basin Recharge Play (6550) parallels the Appalachian Orogen, includes the Blue Creek Anticline and Syncline, and is oriented in a northeast-southwest direction. This is part of the "bull's eye" area where the Pottsville coals are numerous, thick, of high rank, and at relatively shallow burial depths. The play area coincides with the northwest-trending intrusions of fresh water (as identified by low TDS content) into the basin. These fresh-water plumes are especially extensive in the area of the Blue Creek Anticline where enhanced permeability is developed. Depth of burial in the play increases to the southwest, and production has been established at depths from about 500 ft to 3,800 ft in the Cedar Cove and parts of Oak Grove and Brookwood fields. Similar to depth of burial, gas production from individual wells generally increases to the southwest. The potential for additional reserves in this play is good, although limited because of the extensive exploration and production that has taken place. Remaining potential exists at shallower depths in the northeast part of the play area and from unmined coal beds in mining areas.

The Black Warrior Basin–Southeastern Basin Play (6551) is northwest of the Black Warrior Basin Recharge Play (6550) where there is no significant fresh-water flow. Most of the play area is situated away from the "bull's-eye" area so that the coal beds are generally fewer and thinner and lower in rank than in the Recharge Play (6550). As is the case with the Recharge Play, the depth of burial increases in a southwestern direction with a corresponding general increase in daily production rates from individual wells. Production in this play has been established in the Blue Creek, Peterson, Deerlick Creek, Holt, and White Oak Grove degasification fields, and in parts of the Brookwood and Oak Grove degasification fields. The potential for additional reserves in this play is regarded as good and is only restricted by the limited development that has taken place to date.

The Black Warrior Basin–Coastal Plain Play (6552) is located to the southwest of the Southeastern Basin Play (6551); and the Pottsville coal beds probably have the same abundance, thickness, and rank. However, the coal beds are unconformably overlain by Cretaceous and younger coastal plain sediments, which are as thick as 6,000 ft adjacent to the Ouachita Orogenic Belt. Individual wells within the play, are characterized by low production rates, generally less than 50 MCFGPD. Production in this play has been established in the Robinson Bend, Moundville, Little Sandy Creek, Big Sandy Creek, Taylor Creek, and Little Buck Creek fields. The potential for additional reserves in this play is estimated to be fair because of low permeability and possible undersaturation.

The Black Warrior Basin–Central and Western Basin Play (6553) covers a large part of the basin, but there has been limited exploration and no production has been established. The play area is characterized by a few, thin coal beds of low rank that are overlain by coastal plain sediments. In a well drilled in Clay County, Mississippi, specifically to evaluate the coalbed gas potential, only 7 ft of coal were recovered from the Pottsville interval. The coal was of relatively low rank (high-volatile A or B bituminous) with a probable high ash content. The desorption data indicated a gas content of only 100 to 110 Scf/t. The potential for reserves in this play is regarded as fair to poor based on small coal resources and low rank associated with low gas content.

APPALACHIAN BASIN PROVINCE (067)

By Dudley D. Rice and Thomas M. Finn

For the purposes of coal geology, the Appalachian Basin Province (067) is divided into three northeast-southwest trending basins: Northern, Central, and Cahaba Basins. The Northern Appalachian Basin covers an area of approximately 30,000 sq mi and is located in parts of five States–Pennsylvania, West Virginia, Ohio, Kentucky, and Maryland. The Central Appalachian Basin is smaller (about 23,000 sq mi) and occupies parts of Tennessee, Kentucky, Virginia, and West Virginia. The Cahaba Basin is a small, tectonically complex area located within the Appalachian Thrust Belt of Alabama.

Northern Appalachian Basin

The Northern Appalachian Basin is divided into 2 coalbed gas plays, the Northern Appalachian Basin Anticline Play (6750) and the Northern Appalachian Basin Syncline Play (6751).

A geologic overview of the coalbed gas potential of the Northern Appalachian Basin is given by Kelafant and others (1988), Patchen and others (1991), and Schwietering and others (1992). Zebrowitz and others (1991) and Hunt and Steele (1992) provide summaries of reservoir characteristics and technology development for coalbed gas in the entire Appalachian Basin. Diamond and others (1993) described production of coalbed gas associated with underground coal mining.

The coal-bearing interval of the Northern Appalachian Basin is the Pennsylvanian Allegheny, Conemaugh, and Monongahela Groups and the Permian Dunkard Group. The main targets for coalbed gas are seams assigned to, in ascending order, the Clarion/Brookville, Kittanning, Freeport, Mahoning, Pittsburgh, Sewickly, and Waynesburg Coal Groups. Each of these coal groups may contain several individual coal seams that were deposited mainly in a fluvial environment. Data from oil and gas wells indicate that the cumulative coal thickness of all the groups ranges from 10 to 19 ft. The Pittsburgh seam is the thickest (as much as 12 ft), most widespread, and has been mined extensively underground. Many of the coal groups show a eastward trend of increasing number and thickness of individual coal seams. In comparison, data from some proprietary coreholes in West Virginia indicate that the average thickness of the coals more than 2 ft thick over this same interval is greater than 25 ft. Although the coal beds are as deep as 2,000 ft in the basin, the target coal beds for coalbed gas are generally in the depth range of 500 to 1,200 ft.

Coal rank in the basin increases in an eastward direction from high-volatile B bituminous to low-volatile bituminous; a large portion of the coal is actually high-volatile A bituminous in rank. In general, coalification probably resulted from maximum burial during late Paleozoic and early Mesozoic at which time thermogenic gases were generated. However, along the Allegheny Structural Front localized areas of higher rank may have been controlled by advective heating due to fluid flow. As much as 9,000 to 10,000 ft of Permian and Pennsylvanian strata probably have been eroded starting in early Permian time. This uplift and erosion resulted in degassing of some of the original coalbed gas, particularly at shallow depths.

The coalbed gases, as determined from desorbed samples, are composed mostly of methane with variable amounts of CO_2 (as much as 10 percent). The gases are probably of thermogenic origin, although some mixing of relatively recent biogenic gas may have occurred.

Coal-bearing Pennsylvanian strata were folded into many northeast-southwest trending anticlines, which are parallel to the trend of the basin, during the main phase of the Allegheny Orogeny (Permian through Triassic time). Face cleats are oriented perpendicular or at high angles to the axes of the anticlines (NW-SE). Because the cleats are perpendicular to bedding, even on steeply dipping limbs of folds, they probably formed prior to the main phase of the Allegheny Orogeny.

Gas contents in the Northern Appalachian Basin generally vary according to rank and depth. Although gas contents as high as 400 Scf/t have been reported, the values are generally less than 200 Scf/t because of the low rank (high-volatile A bituminous) and relatively shallow depths (generally less than 1,200 ft). In addition to having relatively low gas contents, coals from the Northern Appalachian Basin have longer desorption times (as much as 600 days) as compared to those from other productive basins.

Coalbed gas and conventional oil and gas reservoirs are usually underpressured as compared to hydrostatic pressure (average 0.3 psi). This underpressuring is probably the result of extensive underground coal mining and/or partial degassing of original thermogenic gas.

Information on coalbed hydrology is limited. However, in Indiana County, Pennsylvania, several wells produce water at rates up to 200 barrels per day. The water is supposedly potable, and a permit has been issued for surface discharge.

The in-place coalbed gas resources of the Northern Appalachian Basin in coal beds greater than 1 ft thick and deeper than 300 ft are estimated to be about 61 TCF. Most of this resource is concentrated in the deeper Brookville/Clarion, Kittanning, and Freeport coal groups. This represents, by far, the largest in-place coalbed gas resource in the Paleozoic coal-bearing provinces east of the Mississippi River. However, the economic recoverability of the resource may be adversely affected in this basin by the long desorption time which probably will result in lower production rates.

Major quantities of Pennsylvanian coal are mined underground in the Northern Appalachian Basin and large amounts of methane are emitted in the process. Greene County of Pennsylvania and Monongalia County of West Virginia are two of the top five underground mining counties in the U.S. based on 1991 tonnage statistics. Large mined-out areas occur in the Kittanning, Freeport, and Pittsburgh Coal Groups, particularly in the Pittsburgh, which is the shallowest of these three groups. Some of the largest coal mine emissions rates in the United States have been documented from the Pittsburgh mines in north-central West Virginia. In 1988, West Virginia and Pennsylvania were ranked first and fourth, respectively, in terms of methane emissions from underground mines. In West Virginia, emissions were from both the Northern and Central Appalachian Basins.

The history of coalbed gas production in the Northern Appalachian Basin goes back at least 50 years. Gas was produced from the Pittsburgh coal bed in the Big Run field in Wetzel County, West Virginia starting in 1932. More than 2 BCF of coalbed gas was produced from the field before 1988. Four other gas fields and pools are also reported to have produced coalbed gas: Oakford, Gump, and Waynesburg in Pennsylvania and Pine Grove in West Virginia. During the 1970's and 1980's, the Bureau of Mines and Department of Energy, in association with mining companies, undertook a variety of projects directed toward development of the coalbed gas resource. These projects were only marginally successful because of low production rates (generally <100 MCFGPD) and technical problems, including attempted production from only a single coal seam and inadequate reservoir stimulation. Current activity is limited to one project in Indiana County, Pennsylvania, where 20 wells were drilled in 1992. Six wells were put on production, which was characterized by high water rates initially (as much as 200 barrels per day per well). In addition to technical problems, the development of coalbed gas in the Northern Appalachian Basin has been hindered by questions of gas ownership and environmental problems, mainly disposal of water.

Much of the Northern Appalachian Basin is underlain by shallow gas fields with reservoirs of Mississippian and Pennsylvanian age that have been producing for many years. Therefore, an infrastructure is in place for the development of the shallow coalbed gas resource.

The area of potential Pennsylvanian coalbed gas reserves in the northern Appalachian coal basin corresponds with the area where the Kittanning Coal Group has more than 0.5 BCF/sq mi in-place which generally corresponds to depths of burial greater than 300 ft. The Kittanning has the largest in-place resources of coalbed gas in the basin, and the areas of potential reserves for other coal zones are generally within this same Kittanning area.

6750. NORTHERN APPALACHIAN BASIN–ANTICLINE PLAY

6751. NORTHERN APPALACHIAN BASIN–SYNCLINE PLAY (HYPOTHETICAL)

Potential coalbed gas reserves in the Northern Appalachian Basin are divided into two plays based on structure: Northern Appalachian Basin–Anticline Play (6750) and Northern Appalachian Basin–Syncline Play (6751).

The Northern Appalachian Basin–Anticline Play (6750) is located on the crests and shallow flanks of the tightly folded northeast-southwest trending anticlines. Although the gas contents are generally lower than in the Syncline play because of the shallower depths and partial degassing, the permeability may be tectonically enhanced. In addition, the gas production from both desorption and from the cleats probably will be water free. All the past production of coalbed gas in the basin has come from this play. In the Big Run field, the only field for which production records are available, gas was produced without water from generally unstimulated wells. The undiscovered potential for this play is rated as good. Limiting factors are long desorption times that may affect production rates and low gas contents.

The hypothetical Northern Appalachian Basin–Syncline Play (6751), which covers more area than the Anticline play, is located in the broad structural lows of the basin and below the gas-water contact. The gas contents in this play, as compared to the Anticline play, will undoubtedly be higher because of the greater depth; however the gas production will be accompanied by water. In addition, the permeability values may be lower because of greater depth of burial and lack of enhancement by tight folding. Although no production has been established and the play is hypothetical, its potential for undiscovered resources is considered to be good. Possible limiting factors are long desorption times that may affect production rates and low gas contents.

Central Appalachian Basin

The Central Appalachian Basin contains one coalbed gas play, the Central Appalachian Basin Basin–Central Basin Play (6752).

Adams (1984) and Kelafant and Boyer (1988) described the geologic controls of coalbed gas potential of the Central Appalachian Basin. Summaries of reservoir characteristics and development of technology for coalbed gas in the entire Appalachian Basin are provided by Zebrowitz and others (1991) and Hunt and Steele (1992). Recovery and utilization of coalbed gas from underground mining operations in the Central Appalachian Basin is characterized by von Schonfeldt and others (1982).

The coal-bearing rocks of the Central Appalachian Basin are of Pennsylvanian age, but they are older (Lower and Middle Pennsylvanian) and thicker (as much as 5,000 ft) than those of the Northern Appalachian Basin. The coals are assigned to formations of the Pottsville Group; the formation names and individual coal bed names commonly change across State borders. In southwestern Virginia, where commercial production of coalbed gas is taking place, the main coal-bearing interval is assigned to the Pocahontas, Lee, and Norton Formations. The Pocahontas No. 3 is the deepest (as much as 3,000 ft deep), thickest (as much as 7 ft), and most extensive seam, and the seam is the main target for both underground mining and coalbed gas development. Younger target coal beds for gas are Pocahontas No. 4, Lower Horsepen/Firecreek, War Creek/Beckley, Lower Seaboard/Sewell, and Jawbone/Iaeger (Virginia name followed by West Virginia name). The target coal beds commonly occur in the depth range of 1,500 to 2,500 ft, considerably deeper than in the Northern Appalachian Basin.

The rank of the coals prospective for gas increases to the east from medium- to low-volatile bituminous, considerably higher than in the Northern Appalachian Basin. As in the Northern Appalachian Basin, the coalification pattern was probably controlled by maximum depth of burial in late Paleozoic time, which increased to the east toward the terrigenous source area. Uplift and erosion of a considerable amount of rock probably took place in early Mesozoic time.

Produced coalbed gases in the Virginia portion of the Central Appalachian Basin are composed mainly of methane with as much as 4 percent heavier hydrocarbons and as much as 2 percent CO_2. Isotopic analyses indicate that the gases are of thermogenic origin.

Pennsylvanian strata dip gently to the northwest, whereas Mississippi and older strata dip to the southeast. Structural features of the Central Appalachian Basin are mainly the result of thin-skin tectonics of the Pine Mountain Overthrust Block that moved along décollement zones of shale and coal generally below the Pennsylvanian coal zone. The overthrust block was transported as much as 5 mi to the northwest, which might have resulted in enhanced permeability in the overlying coals. Broad northeast-southwest folds formed prior to thrusting and close to time of deposition. Thin-skin thrust faults and strike-slip faults, which are at high angles to the thrusts, developed during the Allegheny Orogeny (late Pennsylvanian to Permian time). The Russell Fork Fault is a prominent example of a strike-slip fault with as much as 4 mi of lateral displacement. Permeability has probably been enhanced along these faults, and this enhancement may have resulted in some natural degassing of the coal beds.

In contrast to the Northern Appalachian Basin, cleat-and-joint patterns display two dominant trends that reflect two periods of structural deformation. A northeast-southwest set probably formed first and the north-south set was superimposed later during deformation associated with movement of the Pine Mountain Overthrust Block. Some relaxation of the cleats might have occurred during Tertiary time.

Within the area of potential additions to reserves, gas contents are reported to be as high as 700 Scf/t in the Pocahontas No. 3 coal seam, which is extensively mined underground. At equivalent depths and ranks, gas contents in the Central Appalachian Basin are much higher than those in the Northern Appalachian Basin. The variation in gas content between the two basins might be attributed to different maximum burial depths, and burial and tectonic histories. An additional factor is that the Central Appalachian coals desorb in a time period of a few days (1 to 3) as compared to the Northern Appalachian coals that commonly take a few hundred days. These shorter desorption times indicate that gas production rates from individual wells will be higher.

Reservoir pressures measured in the Pocahontas No. 3 seam are close to hydrostatic (0.35 to 0.43 psi) and are higher than those reported from the Northern Appalachian Basin. The pressures may be locally lowered by underground mining activities.

Only minor amounts of water are produced from wells in the Central Appalachian Basin (several barrels per day per well). The total dissolved solids (TDS) of this water are commonly very high (greater than 30,000 ppm) and injection is required. Although precipitation is relatively abundant and some coal beds are thick and continuous, ground-water flow is restricted because the area with potential reserves is fault-bounded and the coal beds do not crop out for possible recharge.

The latest estimate for in-place coalbed gas resources of the Central Appalachian Basin for the six major coal beds (Pocahontas No.'s 3 and 4, Lower Horsepen, War Creek, Lower Seaboard, and Jawbone) is 5 TCF. Additional in-place resources are undoubtedly present in other coal seams. This resource figure is considerably lower than a range of 10 to 48 TCF, which was reported at an earlier date. The earlier large number resulted mainly from lack of depth cutoff, which is critical in this area of high relief where coal beds commonly crop out on hill sides and have probably degassed.

Major quantities of coal are mined in the Central Appalachian Basin, both underground and on the surface. Five counties (Pike, Kentucky; Mingo, Boone, and Logan, West Virginia;, and Buchanan, Virginia) are in the top ten mining counties in the United States based on 1991 statistics, and Buchanan County, Kentucky, was fourth in the country in terms of total tonnage from underground mining. The majority of the underground mining is in the Pocahontas No's. 3, and 4, and Beckley seams. West Virginia and Virginia ranked numbers 1 and 3, respectively, in the United States in 1988 for methane emissions from underground mines. However, parts of West Virginia are located in both the Northern and Central Appalachian Basin.

As is the case with the Northern Appalachian Basin, there have been several cooperative projects between mines and Federal agencies during the past 20 years to produce coalbed gas, most of which were marginally successful and information is not readily available. The cooperative projects were a result of the need to degasify the underground coal mines. Much of the early technology (horizontal and gob wells) to degas underground mines was developed in the Virginia part of the basin.

In 1990, in the Central Appalachian Basin, the State of Virginia and the Federal government adopted a version of "forced pooling" to reduce the obstacle created by uncertainty of gas ownership as opposed to coal ownership. This "forced pooling" procedure in Virginia resulted in a dramatic increase in the development and production of coalbed gas during the period 1990 to 1993. In 1992, southwest Virginia had more than 280 coalbed gas wells that produced about 10 BCF. These wells were completed mostly in the Nora and Oakwood fields and were drilled both in association with and away from underground coal mines. As of 1993, the coalbed gas reserves in Virginia are estimated to be about 220 BCF. West Virginia has recently passed legislation regulating, and perhaps encouraging, the development of coalbed gas.

The prospective area for coalbed gas in the Central Appalachian Basin is underlain by oil and gas fields and an infrastructure for these hydrocarbons is in place. In recent years, many miles of pipeline have been constructed in southwestern Virginia for the collection of coalbed gas from many wells, which have been drilled and are producing in association with and away from underground coal mining.

The topography of the Central Appalachian Basin is characterized by considerable relief (as much as 1,500 ft), and many of the coal seams crop out along hillsides or are less than 500 ft below drainage. This condition severely limits the coalbed gas potential to about 20 percent (5,000 sq mi in West Virginia and Virginia) of the total area. One play is identified in the Central Appalachian Basin, and it is confined to that area where coal beds have gas contents of at least 86 Scf/t and reservoir pressures of at least 215 psi. These values correspond to depths of burial greater than 500 ft. The play area of 5,000 sq mi represents approximately 22 percent of the total coal-bearing part of the Central Appalachian Basin and the gas is contained in about 15 percent of the coal reserves.

6752. CENTRAL APPALACHIAN BASIN–CENTRAL BASIN PLAY

The play can be divided into two areas based on the total gas in place per section, which is the result of coal thickness, depth, and gas content. In the central area, the coal beds are thick and occur at depths greater than 1,000 ft deep indicating higher gas content. In this area, gas in-place is as much as 5 BCF per sq mi. The Nora and Oakwood fields of southwest Virginia are located within this area.

The other area surrounds this central part, and the major seams, such as the Pocahontas No. 3 and 4 and War Creek, are thinner and shallower. The gas in-place volume is less than 1 BCF per sq mi. Only a few wells, which are in Roaring Fork field, have been drilled in this play, and it is essentially undeveloped. The undiscovered potential for this play is considered to be good, although the production rates for individual wells will probably be lower than for the central inner area. The potential for additions to reserves for this entire play is considered to be very good.

Cahaba Basin

The fourth coalbed methane play in the Appalachian Basin Province (067) is the Cahaba Coal Field Play (6753) in the Cahaba Basin of Alabama.

Coalbed methane potential of the Cahaba Basin is described by Telle and Thompson (1987) and Pashin and Carroll (1993). Production information for the basin's only field, Gurnee, is commonly reported with the Black Warrior Basin.

The Cahaba Basin contains one of the principal coal fields within the Appalachian Thrust Belt, a foreland thrust system. To date, most development of coalbed gas has taken place in gently deformed foreland basins, such as the adjacent Black Warrior Basin. The Cahaba coal field, although small in size, provides an example from another tectonic setting where the potential for coalbed gas exists, reflecting the interaction between sedimentation, tectonism, and coalification.

The coal field is situated along the southeast side of the northeast-trending Cahaba Basin which is part of an Alleghanian thrust sheet. Thrusting probably occurred near the margin of a relict rift basin. The basin is bound on the northwest by the Birmingham Anticlinorium and on the southeast by the Helena Thrust Fault. The basin was an actively subsiding depression behind an uplifting thrust ridge during deposition of the Lower Pennsylvanian Pottsville Formation.

The Lower Pennsylvanian Pottsville Formation is the principal coal-bearing interval in the Cahaba coal field. A comparison of the Pottsville section in the adjacent Black Warrior Basin with that in the Cahaba coal field indicates a different depositional history in the Cahaba area, which is related to syndepositional subsidence and thrusting. In the Cahaba, the Pottsville is as much as 9,000 ft thick and can be divided into a lower quartz-arenite measures, middle mudstone measures, and an upper conglomerate measures. It contains 20 informal coal zones and as many as 60 individual coal beds. About 25 coal beds are thick enough to be of economic importance; they are primarily in the mudstone measures. Individual coal beds are as much as 7 ft thick and the net coal thickness can be more than 45 ft thick. Some of the economically important coal zones, in ascending order, are the Gould, Harkness, Wadsworth, Coke, Gholson, Thompson, Montavello, and Maylene.

Coals at the surface in the Cahaba field are high-volatile A bituminous rank, and the rank increases to the southeast. Rank also increases with depth; in the southeast part of the basin the rank of the coal is low-volatile bituminous at 9,000 ft. The rank of these deeper coals increases to the northwest. The diverse relation between rank patterns and structure indicates a complicated burial and thermal history. The main coalification phase occurred during the time of maximum burial and thrusting. However, this regional coalification pattern is overlain by a significant post-tectonic component. This post-tectonic coalification resulted from meteoric recharge in the shallow coal beds and from expulsion of warm orogenic fluids during thrusting in the deeper coalbeds.

Although biogenic gas was probably generated in the shallower coal beds, thermogenic gas was generated in coal beds deeper than 2,500 ft in the structurally deeper parts of the basin. The best potential for thermogenic gas probably occurs in the coal beds of the mudstone measures.

Strata in the Cahaba Basin dip gently to the southeast. The southwest part of the coal field contains numerous folds. The field narrows to the northeast where *en echelon* folds and thrust faults occur in the center of the synclinorium.

In most foreland basins, rectilinear face-butt cleat systems are dominant. These cleats form in a tensile stress field and gas and water are able to flow through them. However, inclined fractures, which result from shearing by structural slip, are abundant in the folded coal beds of the Cahaba coal field. These fractures strike roughly parallel to bedding and dip approximately 60¡ to bedding. The fractures are best developed where the bedding is dipping steeper than 15¡. Thrust faults and associated folds are also common in the dipping coal beds, but, as is the case with the inclined fractures, they do not penetrate the bounding sandstone and mudstone. The ability of gas and water to flow through compressional fractures in thrust belts, such as those found in the Cahaba coal field, is not well understood. However, similar inclined fractures do produce coalbed gas in the Black Warrior Basin along the Blue Creek Anticline.

The desorbed gas contents measured in a core hole in the southeast part of the Cahaba coal field were as much as 380 Scf/t and show a relation between rank and depth. Because of the complex burial and thermal history of the basin, more measurements and modeling of gas contents will be required for basin-wide evaluation. On the basis of the measured gas content values and the estimated coal resources by depth, rank, and location, about 2 TCF of in-place coalbed gas resources have been estimated for the basin with the highest resource potential occurring in the southeast part.

Although some coal is being mined on the surface, no underground mining has taken place in the Cahaba coal field for a number of years. Most of the underground mining was in the southeast part of the basin where the coal rank is higher.

Coalbed gas production was established in the Gurnee field in 1990, the only degasification field in the coal field. In 1993, 64 wells produced about 432 MMCF of coalbed gas. In comparison, 140 wells produced about 542 MMCF of coal gas in 1992.

6753. CAHABA COAL FIELD PLAY

Only one coalbed gas play is identified in the Cahaba Basin, the Cahaba Coal Field Play, and it coincides with the areal extent of the Pottsville Formation. On the basis of the structural complexity of the coal field and the production histories of the existing wells to date, the play is estimated to have fair potential for additional reserves of coalbed gas. However, more detailed studies are needed on foreland thrust systems, such as the Cahaba, to understand the geologic factors controlling the development of potentially large resources of recoverable coalbed gas.

ACKNOWLEDGMENTS

We benefited by discussions with and (or) information from the following individuals or individuals with Alabama Oil and Gas Board, Geological Survey of Alabama, Alaska Division of Geological and Geophysical Surveys, Colorado Geological Survey, Colorado Oil and Gas Conservation Commission, Illinois State Geological Survey, Indiana Geological Survey, Kansas Geological Survey, Kentucky Geological Survey, Mississippi Bureau of Geology, Missouri Division of Geology and Land Survey, New Mexico Bureau of Mines & Mineral Resources, New Mexico Oil Conservation Division, Ohio Geological Survey, Oklahoma Geological Survey, Pennsylvania Bureau of Topographic and Geologic Survey, Pennsylvania Bureau of Environmental Resources, Texas Bureau of Economic Geology, U.S. Bureau of Land Management, U.S. Bureau of Mines, Utah Geological and Mineral Survey, Virginia Division of Mineral Resources, Virginia Division of Gas and Oil, Washington Division of Geology and Earth Resources, West Virginia Geological Survey, Geological Survey of Wyoming, Wyoming Oil and Gas Conservation Commission, Alabama Coalbed Methane Association, Anadarko Petroleum Corp., AMOCO Production Co., Barrett Resources Corp., Bear Production Co., Belden & Blake Corp., Betop Inc., Black Warrior Methane Corp., Carbon Energy International, Coastal Oil and Gas Corp., Consolidated Natural Gas, CWF Energy Inc., Equitable Resources Exploration Co., Gas Research Institute, Fuel Resources Development Co., Martens and Peck Operating Co., Meridian Oil Inc., PG & E Co., Redwine Resources Inc., Resource Enterprises Inc., Stroud Oil Properties, Taurus Exploration Inc., Virginia Gas Co., J.M. Forgotson, and W.T. Stoeckinger. Scientists affiliated with the American Association of Petroleum Geologists contributed significantly to play concepts and definitions. Their contributions are gratefully acknowledged.

REFERENCES

Adams, M.A., 1984, Geologic overview, coal resources, and potential for methane recovery from coal beds of the Central Appalachian Basin--Maryland, West Virginia, Kentucky, and Tennessee, *in* Rightmire, C.T., Eddy, G.E., and Kirr, J.N., eds., Coalbed methane resources of the U.S.: American Association of Petroleum Geologists Studies in Geology No. 17, p. 45-71.

Adams, M.A., and Kirr, J.N., 1984, Geologic overview, coal deposits, and potential for methane recovery from coal beds of the Uinta Basin--Utah and Colorado, in Rightmire, C.T., Eddy, G.E., and Kirr, J.N., eds., Coalbed methane resources of the U.S.: American Association of Petroleum Geologists Studies in Geology No. 17, p. 253-269.

Archer, P.L, and Kirr, J.N., 1984, Pennsylvanian geology, coal, and coalbed methane resources of the Illinois Basin-Illinois, Indiana, and Kentucky, *in* Rightmire, C.T., Eddy, G.E., and Kirr, J.N., eds., Coalbed methane resources of the U.S.: American Association of Petroleum Geologists Studies in Geology No. 17, p. 105-134.

Ayers, W.B., Jr., and Kaiser, W.B., 1992, Coalbed methane in the San Juan Basin of the Western United States: controls on reservoir properties and gas production: Symposium on Coalbed Methane Research and Development in Australia Proceedings, v. 1, p. 1-30.

Ayers, W.B., Jr., Kaiser, W.R., Laubach, S.E., Ambrose, W.A., Baumgardner, R.W., Jr., Scott, A.R., Tyler, R., Yeh, J., Hawkins, G.J., Swartz, T.E., Schultz-Ela, D.D., and Zellers, S.D., 1991, Geologic and hydrologic controls on the occurrence and producibility of coalbed methane, Fruitland Formation, San Juan Basin: Gas Research Institute Topical Report, GRI 91/0072, 314 p.

Barker, C.E., Goldstein, R.H., Hatch, J.R., Walton, A.W., and Wojcik, K.M., 1992, Burial history and thermal maturation of Pennsylvanian rocks, Cherokee Basin, southeastern Kansas: Oklahoma Geological Survey Circular 93, p. 299-310.

Beikman, H.M., Gower, H.D., and Dana, T.A.M., 1961, Coal reserves of Washington: Washington Division of Geology and Earth Resources Bulletin 47, 115 p.

Boreck, D.L., Tremain, C.M., Sitowitz, L., and Lorenson, T.D., 1981, The coal bed methane potential of the Sand Wash Basin, Green River coal region, Colorado: Colorado Geological Survey Open-File Report 81-6, 25 p.

Bostic, J.L., Brady, L.L., Howes, M.R., Burchett, R.R., and Pierce, B.S., 1993a, Preliminary assessment of the potential for coalbed methane in the Forest City Basin, Missouri, Kansas, Iowa, and Nebraska: Tenth Annual International Pittsburgh Coal Conference Proceedings, p. 1056-1061.

Bostic, J.L., Brady, L., Howes, M., Burchett, R., and Pierce, B.S., 1993b, Investigations of the coal properties and the potential for coalbed methane in the Forest City Basin: U. S. Geological Survey Open File Report 93-576, 16 p. plus appendices.

Brady, L.L., 1990, Kansas coal resources, production, and potential use in the near future, *in* Finkleman, R.B., Friedman, S.A., and Hatch, J.R., eds., Coal geology of the Interior coal province, western region: Coal Geology Division Field Trip, The 1990 Annual Meeting of the Geological Society of America, p. 107-127.

Choate, R., Johnson, C.A., and McCord, J.P., 1984, Geologic overview, coal, and coalbed methane resources of the western Washington coal region, *in* Rightmire, C.T., Eddy, G.E., and Kirr, J.N., eds., Coalbed Methane Resources of the United States: American Association of Petroleum Geologists Studies in Geology No. 17, p. 353-372.

Close, J.C., and Dutcher, R.R., 1993, Processes and timing of thermal maturity in the Raton Basin, Colorado and New Mexico: Proceedings of the 1993 International Coalbed Methane Symposium, v II, p. 383-394.

Cluff, R.M., and Byrnes, A.P., 1991, Lopatin analysis of maturation and petroleum generation in the Illinois Basin, *in* Leighton, M.W., Kolata, D.R., Oltz, D.F., and Eidel, J.J., eds., Interior cratonic basins: American Association of Petroleum Geologists Memoir 51, p. 425-454.

Crist, T.E., Kelso, B.S., and Boyer, C.M., 1990, A geologic assessment of natural gas from coal seams in the Menefee Formation, San Juan Basin: Gas Research Institute Topical Report GRI 88/0303, 70 p.

Diamond, W.P., Iannachione, A.T., Puglio, D.G., and Steidl, P.F., 1988, Geologic studies of gassy coalbeds: U.S. Bureau of Mines Bulletin 687, p. 41-78.

Diamond, W.P., Jeran, P.W., and Trevits, M.A., 1993, An analysis of production trends and the potential for increasing gas flow from longwall gob gas vent holes: The 1993 International Coalbed Methane Symposium Proceedings, v. II, p. 443-452.

Ellard, J.S., Roark, R.P., and Ayers, W.B., Jr., 1992, Geologic controls on coalbed methane production: an example from the Pottsville Formation (Pennsylvanian Age), Black Warrior Basin, Alabama, U.S.A.: Symposium on Coalbed Methane Research and Development in Australia Proceedings, v. 1, p. 45-61.

Ericksen, R.L., 1992, A core hole drilled to evaluate the Pennsylvanian coalbed methane potential in Clay County, Mississippi: Mississippi Geology, v. 13, no. 4, p. 71-75.

Friedman, S.A., 1982, Determination of reserves of methane from coal beds for use in rural communities in eastern Oklahoma: Oklahoma Geological Survey Special Publication 82-3, 32 p.

Garcia-Gonzalez, M., MacGowan, D.B., and Surdam, R.C., 1993, Mechanisms of petroleum generation from coal, as evidenced from petrographic and geochemical studies--Examples from Almond Formation coals in the Greater Green River Basin, *in* Wyoming Geological Association Guidebook, Jubilee Anniversary Field Conference, p. 311-324.

Gloyn, R.W., and Sommer, S.N., 1993, Exploration for coalbed methane gains momentum in Uinta Basin: Oil & Gas Journal, v. 91, no. 22, p. 73-76.

Hamilton, D.S., 1993, Stratigraphy and coal occurrence of the Upper Cretaceous Mesaverde Group, Sand Wash Basin; in Geologic and hydrologic controls on coalbed methane: Sand Wash Basin, Colorado and Wyoming: GRI Topical Report GRI-92/0420, p. 23-49.

Harper, D., 1991, Coalbed methane in Indiana: Indiana Geological Survey Occasional Paper 56, 18 p.

Henderson, K.S., and Gazzier, C.A., 1989, Preliminary evaluation of coal and coalbed gas rsource potential of western Clay County, Mississippi: Bureau of Geology, Mississippi Department of Natural Resources Report of Investigation 1, 31 p. plus plates.

Houseknecht, D.W., Hathon, L.A., and McGilvery, T.A., 1992, Thermal maturity of Paleozoic strata in the Arkoma Basin: Oklahoma Geological Survey Circular 93, p. 122-132.

Hunt, A.M., and Steele, D.J., 1992, Coalbed methane technology development in the Appalachian Basin: Gas Research Institute Final Report, GRI-92/0138, 85 p. plus appendices.

ICF Resources Inc., 1990, The United States coalbed methane resource: Quarterly Review of Methane from Coal Seams Technology, v. 7, no. 3, p. 10-28.

Johnson, R.C., Clark, A.C., Barker, C.E., Crysdale, B.L., Higley, D.K., Szmajter, R., and Finn, T.M., 1993, Coalbed methane potential of the Upper Cretaceous Mesaverde and Meeteetse Formations, Wind River Reservation, Wyoming, *in* Keefer, W.R., Metzer, W.J., and Godwin, L.H., eds., Oil and gas and other resources of the Wind River Basin, Wyoming: Wyoming Geological Association Special Symposium, p. 215-242.

Johnson, S.Y., 1985, Eocene strike-slip faulting and nonmarine basin formation in Washington, *in* Biddle, K.T., and Christie-Blick, Nicholas (eds.), Strike-slip deformation, basin formation, and sedimentation: Society of Economic Paleontologists and Mineralogists, Special Publication 37, p. 283-302.

Kaiser, W.R., 1993, Evolution of a basin-scale producibility model: GRI Natural gas supply project advisor group meeting, coalbed methane project area, p. 1-27.

Kaiser, W.R., Scott, D.S., Hamilton, D.S., Tyler, R., McMurry, R.G., and Zhou, N., 1993, Geologic and hydrologic controls on coalbed methane: Sand Wash Basin, Colorado and Wyoming: GRI Topical Report GRI-92/0420, 151 p.

Kelafant, J.R., and Boyer, C.M., 1988, A geologic assessment of natural gas from coal seams in the Central Appalachian Basin: Gas Research Institute Topical Report, GRI 88/0302, 66 p.

Kelafant, J.R., Wicks, D.E., and Kuuskraa, V.A., 1988, A geologic assessment of natural gas from coal seams in the northern Appalachian coal basin: Gas Research Institute Topical Report, GRI 88/0039, 84 p.

Kelso, B.S., Leel, W.G., Jr., and Carr, D.L., 1991, Coalbed methane resource and producibility potential of the Rock Springs Formation, Great Divide Basin, Wyoming, *in* Schwocchow, S.D., Murray, D.K., and Fahy, M.F., eds., Coalbed methane of western North America: Rocky Mountain Association of Geologists, p. 201-208.

Kelso, B.S., Wicks, D.E., and Kuuskraa, V.A., 1988, A geologic assessment of natural gas from coal seams in the Fruitland Formation, San Juan Basin: Gas Research Institute Topical Report, GRI 88/034, 54 p.

Law, B.E., 1984, Relationships of source rock, thermal maturity, and overpressuring to gas generation and occurrence in low-permeability Upper Cretaceous and lower Tertiary rocks, Greater Green River Basin, Wyoming, Colorado, and Utah, *in* Woodward, J., Meissner, F.F., and Clayton, J.L., eds., Hydrocarbon source rocks of the Greater Rocky Mountain region; Rocky Mountain Association of Geologists, p. 469-490.

Law, B.E., and Rice, D.D., eds., 1993, Hydrocarbons from coal: American Association of Petroleum Geologists Studies in Geology 38, 400 p.

Law, B.E., Rice, D.D., and Flores, R.M., 1991, Coalbed gas accumulations in the Paleocene Fort Union Formation, Powder River Basin, Wyoming, *in* Schwochow, S.D., Murray, D.K., and Fahy, M.F., eds., Coalbed methane of western North America: Rocky Mountain Association of Geologists Field Conference Guidebook, p. 179-190.

Levine, J.R., 1993, New perspectives on the indeterminacy of coalbed methane ownership: The 1993 International Coalbed Methane Symposium Proceedings, v. I, p. 305-316.

MacGowan, D.B., Britton, D.R., Miknis, F.P., and Surdam, R.C., 1992, Organic geochemistry and maturation trends of shales and coals, Almond Formation, Mesaverde Group, Greater Green River Basin, Wyoming: A comparison with laboratory maturation of Almond coals by hydrous pyrolysis *in* Wyoming Geological Association 43rd Field Conference Guidebook, p. 221-235.

McCord, J.P., 1984, Geologic overview, coal, and coalbed methane resources of the Greater Green River coal region - Wyoming and Colorado, *in* Rightmire, C.T., Eddy, G.E., and Kirr, J.N., eds., Coalbed methane resources of the United States: American Association of Petroleum Geology Studies in Geology No. 17, p. 271-293.

McFall, K.S., Wicks, D.E., and Kuuskraa, V.A., 1986, A geologic assessment of natural gas from coal seams in the Warrior Basin, Alabama: Gas Research Institute Topical Report, GRI 86/0272, 80 p.

McFall, K.S., Wicks, D.E., Kuuskraa, V.A., and Sedwick, K.S., 1986, A geologic assessment of natural gas from coal seams in the Piceance Basin, Colorado: Gas Research Institute Topical Report, GRI 86/0272, 76 p.

Martin, L.J., Naftz, D.L., Lowham, H.W., and Rankl, J.C., 1988, Cumulative potential hydrologic impacts of surface mining in the eastern Powder River structural basin, northeastern Wyoming: U.S. Geological Survey Investigations Report 88-4046, 201 p.

Merewether, E.A., Krystinik, K.B., and Pawlewicz, M.J., 1987, Thermal maturity of hydrocarbon-bearing formations in southwestern Wyoming and northwestern Colorado: USGS Miscellaneous Investigations Map I-1831.

Nuccio, V.F., Schmoker, J.W., and Fouch, T.D., 1992, Thermal maturity, porosity, and lithofacies relationships applied to gas generation and production in Cretaceous and Tertiary low-permeability (tight) sandstones, Uinta Basin, Utah, *in* Fouch, T.D., Nuccio, V.F., and Chidsey, Jr., eds., Hydrocarbon and mineral resources of the Uinta Basin, Utah and Colorado: Utah Geological Association Guidebook 20, p. 77-93.

O'Neil, P.E., Harris, S.C., Mettee, M.F., Shepard, T.E., and McGregor, S.W., 1993, Surface discharge of wastewaters from the production of methane from coal seams in Alabama, the Cedar Cove model: Geological Survey of Alabama Bulletin 155, 259 p.

Pappajohn, S.P., and Mitchell, T.E., 1991, Delineation of prospective coalbed methane trends in western and central Washington state, *in* Schwochow, S.D., Murray, D.K., and Fahy, M.S., eds., Coal bed Methane: Rocky Mountain Association of Geologists, p.163-178.

Pashin, J.C., 1991, Regional analysis of the Black Creek-Cobb coalbed-methane target interval, Black Warrior Basin, Alabama: Geological Survey of Alabama Bulletin 145, 127 p.

Pashin, J.C., and Carroll, R.E., 1993, Origin of the Pottsville Formation (Lower Pennsylvanian) in the Cahaba synclinorium of Alabama: genesis of coalbed reservoirs in a synsedimentary foreland thrust system: The 1993 International Coalbed Methane Symposium Proceedings, v. II, p. 623-637.

Patchen, D.G., Schwietering, J.F., Avary, K.L., and Repine, T.E., 1991, Coalbed gas production, Big Run and Pine Grove fields, Wetzel County, West Virginia: West Virginia Geological and Economic Survey Publication C-44, 33 p.

Paul, G.W., and Young, G.B.C., 1993, Characterization of Fruitland coal through reservoir simulation: Gas Research Institute Topical Report GRI-92/0460.1,2, 155 p.

Pawlewicz, M.J., Lickus, M.K., Law, B.E., and Dickinson, W.W., 1986, Thermal maturity map showing depth to 0.8 percent vitrinite reflectance in the Greater Green River Basin, Wyoming, Colorado, and Utah: U.S. Geological Survey Miscellaneous Field Studies Map, MF-1890.

Reinecke, K.M., Rice, D.D., and Johnson, R.C., 1991, Characteristics and development of fluvial sandstone and coalbed reservoirs of Upper Cretaceous Mesaverde Group, Grand Valley field, Colorado, *in* Schwochow, S.D., Murray, D.K., and Fahy, M.D., eds., Coalbed methane of western North America: Rocky Mountain Association of Petroleum Geologists Field Conference Guidebook, p. 209-225.

Rice, D.D., 1993, Composition and origins of coalbed gas, *in* Law, B.E., and Rice, D.D., eds., Hydrocarbons from coal: American Association of Petroleum Geologists Studies in Geology No. 38, p. 159-184.

Rice, D.D., Law, B.E., and Clayton, J.L., 1993, Coalbed gas-an undeveloped resource: U.S. Geological Survey Professional Paper 1570, p. 389-404.

Rieke, H.H., and Kirr, J.N., 1984, Geologic overview, coal, and coalbed methane resources of the Wind River Basin-Wyoming, *in* Rightmire, C.T., Eddy, G.E., and Kirr, J.N., eds., Coalbed methane resources of the United States: American Association of Petroleum Geologists Studies in Geology No. 17, p. 295-334.

Ryder, R.T., 1988, Greater Green River Basin, *in* L.L. Sloss, ed., Sedimentary cover--North American Craton, U.S. Geological: Geological Society of America, The Geology of North America, v. D-2, p. 154-165.

Schwietering, J.F., Patchen, D.G., and Markowski, T.K., 1992, Geological aspects of coalbed-methane occurrence in the northern Appalachian coal basin: West Virginia Geological and Economic Survey and Pennsylvania Topographic and Geologic Survey unpublished report, 85 p.

Schwochow, S.D., and Stevens, S.H., eds., 1993a, Coalbed methane–state of the industry: Quarterly Review of Methane from Coal Seams Technology, v.11, no. 1, p. 1-52.

Schwochow, S.D., and Stevens, S.H., eds., 1993b, Coal-seam water-production, treatment, and disposal: Quarterly Review of Methane from Coal Seams Technology, v. 11, no. 2, p. 1-31.

Scott, A.R., 1993, Composition and origin of coalbed gases from selected basins in the United States: The 1993 International Coalbed Methane Symposium Proceedings, v. 1, p. 207-222.

Shepard, T.E., O'Neil, P.E., Harris, S.C., and McGregor, S.W., 1993, Effects of coalbed methane development on the water-quality and fish and benthic invertebrate communities of the Big Sandy Creek drainage system, Alabama: Geological Survey of Alabama Circular 171, 89 p.

Sparks, D.P., Lambert, S.W., and McLendon, T.H., 1993, Coalbed gas well flow performance controls, Cedar Cove area, Warrior Basin, U.S.A.: The 1993 International Coalbed Methane Symposium Proceedings, v. II, p. 529-548.

Sprouls, M., general manager, 1993, Keystone Coal Industry Manual: Chicago, Maclean Hunter Publishing Company, 697 p. plus appendices and maps.

Stevens, S.H., Lombardi, T.E., Kelso, B.S., and Coates, J.M., 1992, A geologic assessment of natural gas from coal seams in the Raton and Vermejo Formations, Raton Basin: Gas Research Institute Topical Report, GRI 92/0345, 84 p.

Stoeckinger, W.T., 1989, Methane from coal in southeast Kansas: The rebirth of an old industry: Proceedings of the 1989 Coalbed Methane Symposium, p. 211-224.

Stoeckinger, W.T., 1990, Kansas coalbed methane comes on stream: Kansas Geological Society Bulletin, v. 66, no. 2, p. 8-12.

Tedesco, S.A., 1992, Coalbed methane potential assessed in Forest City Basin: Oil & Gas Journal, v. 90, no. 6, p. 68-72.

Telle, W.R., and Thompson, D.A., 1987, Preliminary characterization of the coalbed methane potential of the Cahaba coal field, central Alabama: The 1987 Coalbed Methane Symposium Proceedings, p. 141-151.

Trevits, M.A., Finfinger, G.L., and LaScola, J.C., 1993, Evaluation of U.S. coal mine emissions: Society for Mining, Metallurgy, and Exploration, Inc., Preprint number 93-154, 7 p.

Tyler, R., Ambrose, W.A., Scott, A.R., and Kaiser, W.R., 1991, Coalbed methane potential of the Greater Green River, Piceance, Powder River, and Raton Basins: Gas Research Institute Topical Report, GRI 91/0315, 244 p.

von Schonfeldt, H., Pothini, B.R., Aul, G.N., and Henderson, R.L., 1982, Production and utilization of coalbed methane gas in Island Creek Coal Company mines: Proceedings of the Unconventional Gas Recovery Symposium, Pittsburg, Pennsylvania, Society of Petroleum Engineers/Department of Energy Paper 10817, p. 235-244.

Walsh, T.J., and Lingley, W.S., Jr., 1991, Coal maturation and the natural gas potential of western and central Washington: Washington Division of Geology and Earth Resources Open-File Report 91-2, 26 p.

Young, G.B.C., and Paul, G.W., 1993, Reservoir characterization of Mary Lee and Black Creek coals at the Rock Creek field laboratory, Black Warrior Basin: Gas Research Institute Topical Report GRI-93/0179, 114 p. plus appendices.

Zebrowitz, M.J., Kelafant, J.R., and Boyer, C.M., 1991, Reservoir characterization and production potential of the coal seams in northern and Central Appalachian Basins: The 1991 Coalbed Methane Symposium Proceedings, p. 391-402.

Table 1. List of plays with regions and provinces for which potential additions to reserves of coalbed gas were assessed [* indicates hypothetical play]

PACIFIC COAST REGION 2

Western Oregon–Washington Province (004)

Western Washington–Bellingham Basin* Play (0450)
Western Washington–Western Cascade Mountains* Play (0451)
Western Washington–Southern Puget Lowlands* Play (0452)

COLORADO PLATEAU AND BASIN AND RANGE REGION 3

Uinta-Piceance Basin Province (020)

Uinta Basin

Uinta Basin–Book Cliffs Play (2050)
Uinta Basin–Sego* Play (2051)
Wasatch Plateau–Emery Play (2052)

Piceance Basin

Piceance Basin–White River Dome Play (2053)
Piceance Basin–Western Basin Margin Play (2054)
Piceance Basin–Grand Hogback* Play (2055)
Piceance Basin–Divide Creek Anticline Play (2056)
Piceance Basin Igneous* Play (2057)

San Juan Basin Province (022)

San Juan Basin–Overpressured Play (2250)
San Juan Basin–Underpressured Discharge Play (2251)
San Juan Basin–Underpressured Play (2252)

ROCKY MOUNTAINS AND NORTHERN GREAT PLAINS REGION 4

Powder River Basin Province (033)

Powder River Basin–Shallow Mining-Related Play (3350)
Powder River Basin–Basin-Center Play

Wind River Basin Province (035)

Wind River–Mesaverde Play (3550)

Southwestern Wyoming Province (037)

Greater Green River Basin–Rock Springs Play (3750)
Greater Green River Basin–Iles Play (3751)
Greater Green River Basin–Williams Fork Play (3752)
Greater Green River Basin–Almond Play (3753)
Greater Green River Basin–Lance Play (3754)
Greater Green River Basin–Fort Union Play (3755)

Raton Basin Province (041)

Northern Raton Basin Play (4150)
Raton Basin–Purgatoire River Play (4151)
Southern Raton Basin Play (4152)

MIDCONTINENT REGION 7

Forest City Basin Province (056)

Forest City Basin–Central Basin* Play (5650)

Cherokee Platform (060)

Cherokee Platform–Central Basin Play (6050)

Arkoma Basin Province (062)

Arkoma Basin–Anticline Play (6250)
Arkoma Basin–Syncline* Play (6251)

EASTERN INTERIOR REGION 8

Illinois Basin Province (064)

Illinois Basin–Central Basin Play (6450)

Black Warrior Basin Province (065)

Black Warrior Basin Recharge Play (6550)
Black Warrior Basin–Southeastern Basin Play (6551)
Black Warrior Basin–Coastal Plain Play (6552)
Black Warrior Basin–Central and Western Basin* Play (6553)

Appalachian Basin Province (067)

Northern

Northern Appalachian Basin–Anticline Play (6750)
Northern Appalachian Basin–Syncline Play (6751)

Central

Central Appalachian Basin–Central Basin Play (6752)

Cahaba

Cahaba Coal Field Play (6753)